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APPLICATION OF HORIZONTAL WELLS IN COMBINATION WITH VERTICAL WELLS FOR ATHABASCA OIL SAND DEPOSITS

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EXECUTIVE SUMMARY

Horizontal wells are becoming increasingly important in heavy oil production. The representation of horizontal wells in simulators is still done in the conventional manner, viz. without consideration of the wellbore flow, whether it is an injector or producer. This study was designed to examine this aspect of horizontal injectors and producers in the context of steamflooding simulations of the McMurray formation.

The previously developed horizontal production and injection well models were incorporated into a steam injection simulator, using a simplified approach. Simulator test runs showed that this approach influenced the results to a small extent only (at least for the conditions of this study) in the case of a horizontal producer, compared to the conventional approach of assigning well indices to the blocks, without consideration of multiphase flow in the wellbore. On the other hand, proper representation of a steam injector affected the results considerably, showing that the conventional approach would yield optimistic oil recovery predictions.

Many combinations of horizontal and vertical wells were tested. In particular, two of these stand out: a horizontal injector-horizontal producer combination, and another utilizing horizontal drainholes and injectors, with four branches, placed in the lower layer of the formation. In some instances, a horizontal injector-vertical producer combination may also be very effective. Horizontal injectors may provide the desired injectivity, without the injection pressures reaching prohibitively high levels, in formations such as the McMurray oil sands. This application of horizontal wells, though uncommon, may help to conduct succesful steamfloods in the oil sands formations.

SOMMAIRE

Les puits pétroliers horizontaux sont en voie de devenir une importante technologie dans la production des pétroles lourds. La représentation de ces puits dans les simulateurs numériques est cependant toujours effectuée de façon conventionnelle, c'est-à-dire sans considération pour l'écoulement dans le conduit des puits, qu'ils soient utilisés comme injecteurs ou producteurs. La présente étude a été planifiée de façon à examiner en détail l'écoulement dans les puits horizontaux d'injection et de production en simulant l'extraction du pétrole par le lavage à la vapeur des sables bitumineux de la Formation McMurray (Athabasca).

Les modèles numériques utilisés pour décrire l'écoulement dans des puits horizontaux d'injection et de production ont originalement été développés par l'auteur lors de travaux ultérieurs. Ils ont d'abord été incorporé dans un simulateur d'injection de vapeur en utilisant une approche simplifiée. Les tests initialement conduits avec le simulateur ont démontré que l'approche simplifiée n'influence que très légèrement les résultats dans le cas où le puits producteur est horizontal. Au contraire, la représentation exacte et conventionnelle des puits d'injection, celle où l'on assigne des indices généraux à chacun des blocs sans considérer l'écoulement à plusieurs phases dans le conduit des puits, affecte considérablement les résultats donnant lieu à des prédictions trop optimistes de récupération du pétrole.

Plusieurs agencements de puits verticaux et horizontaux ont été testés. Les combinaisons qui se dénotent le plus sont :

- le jumelage de puits d'injection et de production horizontaux,
- la combinaison de puits de drainage horizontaux et de puits d'injection verticaux avec quatre branches placées dans la couche inférieure de la formation.

Mentionnons également que dans certains cas, la mise en place d'un puits injecteur horizontal et d'un puits producteur vertical peut s'avérer être efficace.

Enfin, l'étude démontre qu'il est possible que l'utilisation de puits injecteurs horizontaux fournissent l'injectivité désirée sans que les pressions d'injection atteignent les hauts niveaux prohibés dans les formations telles que les sables bitumineux du McMurray. Cette application des puits horizontaux pourra possiblement conduire à la reussite de la méthode de récupération peu commune du lavage à la vapeur dans les sables bitumineux de l'Athabasca.

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INTRODUCTION

Steam injection is the only Enhanced Oil Recovery (EOR) method that has been commercially successful in heavy oil reservoirs, such as those of California (thick, relatively homogeneous, high oil saturation, high permeability and porosity, low reservoir pressure, oil viscosity 1000-2000 mPa.s). The two modes of steam injection, viz. cyclic steam stimulation and steamflooding (or steam drive) work very well in such reservoirs, and are commonly used in some combination suited to the reservoir. In Canada, a variation of cyclic steam stimulation has proved to be commercially viable in Cold Lake. In this version,steam is injected at fracture (or parting) pressures. Steamflooding has not been successful in the oil sands, although pilot tests have been conducted.

The oil sands of Athabasca pose a special challenge. They meet essentially all criteria for successful steamflood operation, except that the oil viscosity is a few million mPa.s. Steam injection (or, for that matter, injection of any fluid)is impractical under those conditions. Injection under fracture conditions is not desirable in the steamflood mode, in view of premature steam breakthrough,and other operating problems. Thus, the formation must be stimulated prior to steam injection to lower the viscosity of the in-place oil.

Several processes were considered for the thermal stimulation of the Athabasca oil sands, in a previous study by Farouq Ali and Verma (1). These included:cyclic steam stimulation of the wells to be used for the steamflood, stimulation of the formation by limited in situ combustion, followed by a long shut-in period, and conduction heating of the formation, using a system of parallel fractures (or other channels with adequate fluid conductivity). Of these techniques, cyclic steam stimulation was considered to be the most effective method of preheating the formation (and, of course, for producing a substantial amount of oil at the same time).

In the present study, it was assumed that the formation has been preheated by a suitable method, to a temperature of 80° C, or 100° C. At this point, the viscosity of in-place bitumen is less than 2000 mPa.s. One of the general steamflooding criteria is that the oil viscosity be no more than 1000 mPa.s, at the reservoir conditions. Several simulation runs at the reservoir temperature of 15° C were also carried out. Results of these runs are discussed. The main problem was that the injection pressures reached very high levels.

PREHEATING OF THE McMURRAY FORMATION

In the following, the principal findings of the study (1) on preheating of the McMurray formation are summarized. (Wabiskaw formation was also considered in the aforesaid study). The basic criterion was that the oil viscosity be lowered to a level of about 1000 mPa.s, usually considered to be the maximum for the application of a flood type process (for typical permeabilities and thicknesses in the oil sands deposits).

The preheating methods investigated were:

- cyclic steam stimulation for several cycles
- cyclic steam stimulation with long soak periods
- limited steamflood, followed by a shut-in period
- in situ combustion over a limited interval, followed by a shut-in period
- in situ combustion in a preheated formation
- fracture heating, leading to conduction heating of the oil sands formation

Based upon the numerical simulations carried out, cyclic steam stimulation was judged to be the most efficient way of formation preheating in order to conduct a flood type process. However, for typical operating conditions, even after three cycles the heated formation area was equivalent to a flood pattern of about one hectare. An important advantage of cyclic steam stimulation is, of course, that it is an important recovery process per se, and a considerable volume of oil is produced while preheating the formation.

A long soak period, after steam breakthrough, in a steamflood type operation, was found to be inefficient as a preheating method, both from the standpoint of oil recovery and temperatures achieved in the formation. In situ combustion was the least effective of the methods examined. Fracture heating was efficient, for small spacings only, of the order of 10 m.

PREVIOUS STUDIES ON HORIZONTAL WELL MODELLING
Task 1

Several mathematical models of horizontal wells have been described in recent years. This chapter presents a resume of the models.

Numerical simulation studies of horizontal wells have been reported by many investigators, showing favourable response in most instances. Such studies still lack a proper representation of a horizontal well insofar as flow around the well is assumed to be radial. Laboratory studies are few and far between for reasons of difficulty of modelling and scaling.

Borisov[3] expanding on previous work by Merkulov (1958) and others, examined the idea of oil field production using horizontal and highly-deviated wells. In the case of oil flow toward an isolated horizontal well located in the center of a homogeneous and isotropic bed, an approximate equation was derived to calculate oil production rate based on the total flow resistance which consisted of two components: external resistance to inflow, and internal resistance due to flow inside the well. Analysis was also carried out to investigate the use of horizontal wells in reservoirs bounded by gas cap and water leg. An interesting conclusion was: the flow of a unit of length of a selectively perforated vertical well was much higher than that of a unit of length of a horizontal well.

Chang, Tomutsa, and Tham[4] reported the incorporation of horizontal and slanted wellbore models into BOAST, with the aim of predicting potential production rates for such wells. A special feature of the horizontal wellbore model is that the productivity index for the wellbore within each penetrated grid block consists of three component productivity indices in the x-, y-, and z-directions. The model can be run under either pressure or rate constraints, and can be used to calculate the productivity index based on the length and location of the wellbore within a block. The model results were checked against analytical formulae of transient pressure behaviour in an infinite slab reservoir and published analytical type curves, with good agreement with both. It was concluded that the advantage of horizontal/slanted wells over vertical wells in production rates depends primarily on the length of the wellbore, slant angle, vertical and radial permeability, and well eccentricity. It was also noted that vertical permeability

discontinuities have a smaller impact on the production rate of a slanted well than that of a horizontal well.

Dikken[5] studied the pressure drop in horizontal wells and its effect on the production performance. He noted that the commonly used assumption of laminar flow in horizontal wells is not necessarily true for most practical situations, and proceeded to prove this with calculated examples. A second-order differential equation linking single-phase turbulent well flow with stabilized reservoir flow was derived and solved numerically for various boundary conditions. The following conclusions were drawn: turbulent well flow in the horizontal section of a horizontal well may result in an appreciable reduction of drawdown at various positions away from the lifting end of the section, and that the total production will level off and become virtually constant when the well length exceeds a certain critical value. It can be said that this study was the first to investigate the effect of the pressure gradient inside the well on well performance. The importance of this can certainly not be ignored keeping in mind that future horizontal wells, in view of new innovations in lateral drilling technology, will tend to be much longer.

Rial[6] numerically investigated the effectiveness of steamflooding with a horizontal steam injector located at the bottom of a heavy-oil reservoir. A three-dimensional numerical model accounting for three-phase flow, steam distillation, temperature-dependent relative permeabilities, gravity, viscous and capillary forces was developed. The input data for the model were representative of the Kern River field, California. The results revealed that: a horizontal steam injector had a more consistent areal sweep than a conventional vertical steam injector, a horizontal wellbore was more efficient than a vertical wellbore for steamflooding with regard to temperature and residual oil phase distributions, and a horizontal wellbore swept more heat through the grid system and produced more energy than a conventional vertical wellbore. For the field under consideration, the study showed that when a horizontal wellbore was used for steam injection, 71% of the original oil in place (OOIP) was recovered after 15 years, while only 58% of the OOIP was recovered for a vertical wellbore for the same time period.

Jain and Khosla[7] used a commercial simulator to predict steamflooding recovery performance of Athabasca oil for three different combinations of horizontal and vertical wells: the first configuration had two 150 m-long parallel horizontal wells which were spaced 60 m apart, the second configuraton had a 300 m-long horizontal steam injector and a vertical producer in communication with it, and the third configuration had a

400-m long horizontal producer with two vertical injectors in communication with each other to create a heated plane over the horizontal well. In the last configuration, steam-assisted gravity drainage was modelled, while in the first two steamdrive effects were assumed. The results showed that the last well configuration of a horizontal producer with a heated plane between two vertical injectors above it, despite having a larger drainage area, yielded the highest daily oil production rate and cumulative oil recovery.

Huang and Hight[8] conducted numerical simulation studies to examine the effectiveness of horizontal wells to reduce steam override in a mature steamflood, as well as to prevent steam override in new operations. A commercial three-dimensional, three-phase flow thermal simulator which included the effects of gravity, viscous, and capillary forces was used. Heat transfer was modelled by conduction and convection, and relative permeability curves used were temperature dependent. A notable feature of the model was its capability to simulate well completions in any direction. Reservoir properties used were typical of a California unconsolidated heavy-oil reservoir. Simulation results indicated that horizontal wells were very effective in recovering oil in areas bypassed by overriding steam. For the 18.5-acre, inverted 13-spot pattern studied horizontal wells improved oil recovery and shortened project life, as well as reduced oil saturation in blind spots from 60% to 30%. In addition, incorporating horizontal wells at the start of a steamflood project with the same well pattern and spacing led to a 72% OOIP recovery efficiency in seven years, and resulted in a residual oil saturation of 26% in blind spot areas.

Hsueh[9] presented results of a numerical simulation study of the HASDrive (Heated Annulus Steam Drive) process. In short, this in-situ process utilizes a horizontal, cased, unperforated pipe running between a vertical steam injector and a vertical producer. High-pressure, high-temperature steam is circulated through the pipe which heats the surrounding tar sand by conduction. In this sense, the heated annulus acts as a communication path for steam drive between the injection and production wells. The main recovery mechanism in the HASDrive process is believed to be gravity drainage, which is also assisted by a steam drive. The effects of grid block size, relative permeability, heat transfer coefficient, HAS pipe diameter, pattern width, and well configuration were investigated. The simulation results showed the process to be effective for improving areal sweep efficiency and preventing premature steam breakthrough. The major advantage of this process over the conventional practice of creating fractures between the steam injector and oil production wells is its

ability to provide a well-controlled fluid communication path which can be kept open throughout the life of a project. In addition, it can also lead to high steam conformance and reduce heat loss through fractures.

Dietrich[10] described the Kern River horizontal-well steam pilot which involved the drilling and completion of eight horizontal wells of varying lengths from a common vertical shaft. The horizontal wells were arranged in a spoke-like fashion, 450 m apart from each other, and used for production. Poor oil response in initial periods was believed to have been caused by the placement of the horizontal wells in a highly unfavourable reservoir environment of low vertical permeability and depleted oil saturation and pressure conditions at the pilot site. The termination of the pilot was followed by numerical studies which aimed to develop better operating strategies and to predict future potential. The main conclusion derived from the simulation studies was that horizontal wells can be very efficient at reducing steam override.

Folefac and Archer[11] discussed the simulation of horizontal wells in thermal recovery processes for heavy oils. The objectives of the study were to evaluate the effectiveness of horizontal wells in improving the productivity and injectivity indices, the potentials of horizontal wells in increasing sweep efficiency at breakthrough by minimizing gravity override and gravity segregation, and the effectiveness of horizontal wells in controlling coning tendencies. Conformal mapping techniques were employed to transform complex flow geometries in horizontal wells into simpler geometries for which the flow rates and productivity indices can be readily calculated. An important assumption used in the representation of the horizontal well continuum by various discretizing methods was that the horizontal well has infinite conductivity, i.e. there is no pressure drop along the well. The authors concluded that the improvements in productivity by horizontal wells are strongly dependent on well length and the lateral extent of the reservoir. In addition, horizontal wells can maintain a stable displacement front for flow processes dominated by gravity forces, and thus lead to improved sweep efficiency. Finally, it was shown that increasing the horizontal well length in reservoirs exhibiting coning tendencies will reduce cone height and increase the critical production rate.

Combe, Burger, Renard, and Valentin[12] numerically investigated the improvements in recovery performance of steam drive when horizontal wells are employed. The cases considered included a wide range of fluid and reservoir characteristics, different spatial distributions for vertical and horizontal wells, as well as different injection strategies. The results showed

horizontal wells to be very efficient for exploiting thin, marginal heavy oil reservoirs with low oil mobility. Studies were also carried out for layered reservoirs with tight streaks between layers, and reservoirs with initial mobile water saturation. It was predicted, for the first case, that a significant acceleration of oil production would be achieved if horizontal wells are drilled in various layers than would have been if all the wells are in one layer.

Perhaps the only coupled production wellbore and reservoir simulator for steam injection is the one reported by Stone, Edmunds and Kristoff[13]. This simulator was designed for the UTF project. The wellbore model is of the mechanistic type, and requires a number of assumptions for implementation. Mass, heat, and momentum balance equations were formulated for the flow of bitumen, water, gas, and emulsion in the tubing as well as the casing. These were coupled with the reservoir flow equations. Numerical solution was effected by use of finite differences. The model was used to predict temperature distributions in the oil sand in a steam-assisted gravity segregation type process.

In a recent paper, Nghiem, Collins and Sharma[14] compared the performances of a number of isothermal horizontal well simulators developed by various investigators, and tested for a a predefined problem, for use in black oil simulators for conventional oils. All of these utilized the flow regime type approach, where an appropriate correlation was employed, having identified the flow regime.

CHOICE OF THE SIMULATOR FOR THIS STUDY
Task 2

The original intent of this study was to incorporate the horizontal injector and producer models, developed in the previous study, into the SSI THERM simulator that is used by Petro-Canada, in-house. The author, too, has considerable experience using this simulator.

In Nov., 1990, Mr. G. Sarioglu and Dr. D. Towson discussed the possibility of modifying the aforesaid simulator, and incorporating the wellbore models developed in the previous study (2) into the SSI simulator. This approach was unsuccessful, first, because of the proprietary nature of the simulator source code, and Petro-Canada's agreement with SSI to this effect, and secondly, because SSI were reluctant to have an outside person modify the code. Other simulators were also considered for this purpose, with negative results.

It was therefore decided that the author would incorporate the wellbore model into one of his own steam injection simulators, and complete the study on this basis. It was understood that the said simulator was not a deliverable under this contract. Rather, the objective was to use this simulator, in lieu of one of the other commercial simulators, to expedite the present study. This approach also turned out to be vastly more convenient.

Numerical Simulator

The numerical simulator used for this study is a black oil type three-dimensional, three-phase thermal simulator, capable of simulating any steam injection process - cyclic steam stimulation, conduction heating, or steamflooding - acting singly or in combination. The simulator employs a fully implicit formulation, together with a direct solution scheme. It has been extensively tested for field applications.

A limiting factor in the simulator use was the computer time. The runs conducted utilized a 5x5x2 grid to represent one-quarter of a five-spot pattern. The runs were limited to 500 seconds of machine time. In most instances, this permitted a field simulation of two-to-three years.

The simulator does allow the injection pressure to rise to any value, in case it is forced to inject steam at a specified rate. (Other options include automatic reduction of the steam injection rate according to the maximum pressure specified).

In such an instance, steam properties at the critical point are employed. Simulations of this type, even though they may be unrealistic, provide insight into the limiting behaviour. In the oil sands simulations, the steam injection rate dropped to very low values, when the maximum pressure option was used.

INCORPORATING THE WELL MODEL INTO THE SIMULATOR
Task 3

Horizontal/vertical wellbore models were developed in a previous study carried out by the author (2). The objective of this task was to incorporate the well models developed previously into the steam injection simulator mentioned in the previous chapter.

Wellbore Simulators: Injection Well

The injection well simulator is a comprehensive representation of multiphase flow in a steam injection well of any form, allowing for heat loss to the surroundings, pressure drop due to friction, accounting for flow regimes in the well, and variable steam injection and offtake rates along the well column.This model has been used successfully for many cases of steam injection well performance prediction. The model, as used, gives the instantaneous steam pressure and quality at the offtake points along the well column. The steam offtake rates at the points (representing the perforations) are either specified, or supplied internally by the simulator itself.

Production Well

The production well simulator developed previously accounts for three-phase flow in a horizontal well of any shape, using flow regime correlations. It is basically a nonthermal simulator, although temperature effects on the properties of the variables involved have been incorporated. The simulator yields the instantaneous well pressure at various points inside the well, for arbitrary inflow rates of oil, water and gas along the length of the well.

Incorporating the Well Models into the Steam Injection Simulator

This part of this study turned out to be the most time-consuming. The original intent was to incorporate the injection and production well models in an implicit manner. Much effort was expended in this direction, essentially showing that the proper approach was to rewrite a large portion of the simulator, which was beyond the scope of this study. Finally, it was decided to couple the wells in an explicit manner, in other words, the values of the variables at the previous time level are used to compute the well hydraulics. While simpler in principle, this approach caused stability problems, which were eventually solved, through smoothing the injection or production well input to the simulator.

At the present time, the combined wellbore-reservoir simulator requires a considerable amount of preparatory and computational work for each simulation. The procedure can be summarized as follows. The well models are built into the steam injection simulator as subroutines. The well data as well as fluid and the surrounding rock properties are read into the main program. After every *n* time steps in the main program, the wellbore injection model is executed, obtaining steam injection pressures and qualities for the current offtake rates at the perforated blocks. The process continues in this manner. The results showed that it may be necessary to alter *n* within the same run. The production well calculations are similarly carried out after every *m* time steps of the main program. The prevailing intake rates at the perforated blocks are used to calculate the pressure distribution in the wellbore. These pressures are used to update the intake rates for subsequent computations in the main program. This part of the calculation requires some experimentation to determine values of *m* during the simulation.

TESTING THE MODEL
Task 4

The purpose of this task was to test the combined steam simulator-wellbore simulator for a variety of conditions. Many runs and much effort was expended in this phase of the project.

Data Used

The McMurray formation data used in the model tests was taken from the previous study (1), and is grouped together in Appendix B. Table B.1 gives the layering of the McMurray formation, and the properties of each layer, oil viscosity data as a function of temperature. Tabulated values are given in Table B.2, while the plots are shown in Figures B.1 and B.2. The tabulated relative permeability data is given in Table B.3, B.4, and B.5. Reservoir rock and fluid properties are listed in Tables B.6 and B.7, respectively. Only the data called for by the simulator were used for this study.

Types of Tests Conducted

Well over 20 simulations were carried out under this task. The main objectives were (i) to determine the most appropriate set of conditions for subsequent runs, and (ii) to test the well models built into the simulator, for the selected conditions. The reservoir data used spanned a range of values; the final values are given in the next chapter.

SETTING UP THE VARIABLES
Task 5

The selection of the variables for the numerical simulations was based upon the data for the McMurray formation, used in the previous formation preheating study.

The following reservoir data was selected for the main runs:
Pattern: Five-spot, pattern area 2 ha, or 4.94 acres.

Formation: Two layers

Top Layer: 67.6 ft thickness
Horizontal permeability 1.84 darcies
Vertical permeability 0.439 darcies
Porosity 29.4%
Oil saturation 75%
Gas saturation 0%

Bottom Layer: 74.2 ft thickness
Horizontal permeability 1.58 darcies
Vertical permeability 0.631 darcies
Porosity 33.7%
Oil saturation 80%
Gas saturation 0%

Several observations must be made. First, the geological description of the McMurray formation (Table B.1) is very complex, and the above layering is only an approximation. Any greater detail would have required prohibitive computer time and cost. At the same time, the shale separating the two layers is nearly impermeable, and one alternative would have been to consider the two layers separately, with a detailed description of each layer.

The oil saturations correspond to water saturations of 25 and 20% in the upper and lower layers, respectively. These are slightly above the averaged values. The actual formation water saturations are above the irreducible values, which provide the initial injectivity of steam - only if the formation is assumed to be preheated. (Gas saturation is zero). Even then, the injection well pressure in many instances exceeded the fracture pressures.

The pattern size of 2 ha (about 5 acres) was chosen on the basis of the resource base in that volume (approximately 1.35 MMBbl), as well as the feasibility of achieving reasonable

steam injection rates over the pattern. The first three runs employed a pattern size of 10 acres, for vertical injector-vertical producer type simulations. For the calculated productivity index, the larger pattern did not lead to any appreciable increase in the oil production rate, yet the injection pressures exceeded the fracture pressure (1200 psia, or about 8 MPa). The observed behaviour of a vertical injector-horizontal producer was also similar for the two pattern sizes. The productivity index was arbitrarily varied to observe the effect on pressure. Doubling the productivity index increased the oil production rate, but really the pressure drop at the producer increased, while the high pressures at the injector remained largely unchanged.

It should be reiterated that the steam simulator used does allow the injection pressure to rise to very high values, even though they may be unrealistic. In such an instance, the steam properties at the critical point are employed.

The choice of steam injection rate was made by trial and error, simulating different rates and looking at the resulting steam injection pressures. Initially a rate of 500 B/D of steam (cold water equivalent) was tried, for a quadrant of a five-spot (i.e. 2000 B/D for the whole five-spot. *Please note that all simulation results are given for one-quarter of a five-spot; for the whole five-spot pattern, the volumes are to be multiplied by 4)*. This proved to be too high, with pressures reaching very high values. An example is shown in Table 1. Figures 1 to 3 (referred to in the next chapter) show the oil production rate as a function of time and steam injected, and oil-steam ratio, respectively.

A difficult task was the selection of formation preheat in order to conduct a successful steamflood. The initial temperature was assumed to be 80° or 100°C; the latter was used for most of the runs. A few runs, dicussed under Task 8,were also repeated for the original formation temperature of 15°C. These were successful computationally, but led to very high pressures.

Table 1

Injection Pressure Behaviour for Steam Injection at 500 B/D, per Quadrant, Preheat of 80°C, Vertical Injector, Vertical Producer.

FINAL OIL PRESSURE, PSIA

LAYER 1

J/I	1	2	3	4	5
1	418.5	417.6	378.6	359.6	361.0
2	411.6	390.2	366.7	350.3	341.2
3	378.6	366.7	346.8	332.4	318.2
4	359.6	350.3	332.4	306.0	272.8
5	361.0	341.2	318.2	272.0	77.6

INJ. PROD.

LAYER 2

J/I	1	2	3	4	5
1	478.2	411.3	383.7	372.6	368.0
2	411.3	380.4	376.3	368.4	364.1
3	383.7	376.3	366.1	358.0	349.8
4	372.6	368.4	358.0	340.6	311.3
5	368.0	364.1	349.8	311.3	200.7

t=1 day

J/I	1	2	3	4	5
1	744.3	686.3	458.6	401.8	377.0
2	686.3	604.7	427.2	382.6	366.7
3	458.6	427.2	366.2	346.2	322.6
4	401.8	382.6	346.2	306.0	286.4
5	377.0	366.7	322.6	286.4	186.8

J/I	1	2	3	4	5
1	566.7	562.6	453.4	410.8	390.0
2	562.6	477.8	438.0	382.8	372.7
3	453.4	428.0	384.6	351.6	337.6
4	410.8	382.8	361.6	321.0	278.8
5	390.0	372.7	337.6	278.8	177.1

t=20 days

J/I	1	2	3	4	5
1	2121.8	778.3	768.6	438.8	421.4
2	778.3	786.6	472.8	418.8	403.8
3	768.6	472.8	418.8	388.8	387.8
4	438.8	418.8	388.8	366.6	368.6
5	421.4	403.8	387.8	368.6	184.3

J/I	1	2	3	4	5
1	1078.8	841.8	814.7	493.4	468.0
2	841.8	838.1	537.4	467.7	450.1
3	814.7	837.6	467.8	434.8	411.3
4	493.4	467.7	434.8	391.1	343.8
5	468.0	450.1	411.3	343.8	217.3

t=50 days

J/I	1	2	3	4	5
1	3748.8	884.3	682.7	442.1	388.0
2	884.3	880.3	544.1	388.4	336.0
3	682.7	544.1	381.8	316.1	288.8
4	442.1	388.4	316.1	281.1	246.2
5	388.0	336.0	288.8	246.2	166.3

J/I	1	2	3	4	5
1	3842.2	710.7	701.6	493.8	498.8
2	710.7	707.6	586.8	411.8	384.9
3	701.6	586.8	414.8	388.7	344.1
4	493.8	411.8	388.7	333.6	282.3
5	498.8	384.8	344.1	282.3	176.8

t=76 days

J/I	1	2	3	4	5
1	3815.6	857.5	646.8	578.7	378.1
2	857.5	854.6	607.8	388.7	338.3
3	646.8	607.6	418.8	388.6	282.3
4	578.7	388.7	388.6	288.4	237.3
5	378.1	338.3	282.3	237.3	148.4

J/I	1	2	3	4	5
1	3827.8	881.6	676.4	682.2	417.8
2	881.6	878.4	603.6	426.6	384.4
3	676.4	603.6	453.8	388.3	337.2
4	682.2	426.6	388.3	313.6	274.8
5	417.8	384.4	337.2	274.8	188.8

t=100 days

J/I	1	2	3	4	5
1	4082.5	3876.3	843.4	834.8	836.1
2	3876.3	849.8	842.8	855.7	846.4
3	843.4	842.8	883.1	831.8	406.1
4	834.8	855.7	831.8	366.8	288.8
5	836.1	846.4	406.1	288.8	182.7

J/I	1	2	3	4	5
1	3493.8	1184.4	887.3	843.7	786.2
2	1184.4	888.2	887.1	890.4	873.8
3	887.3	887.1	886.8	838.7	414.8
4	843.7	890.4	888.7	361.8	303.3
5	786.3	873.8	414.8	303.3	182.8

t=150 days

J/I	1	2	3	4	5
1	4103.8	3883.1	1171.3	1186.2	1182.1
2	3883.1	3780.7	1167.7	1180.2	1067.0
3	1171.3	1167.7	1188.2	1023.8	883.3
4	1186.2	1180.2	1023.8	783.8	587.4
5	1182.1	1067.0	883.3	587.4	383.1

J/I	1	2	3	4	5
1	2081.4	1886.7	1174.8	1186.4	1078.4
2	1886.7	1171.8	1186.8	1082.2	888.8
3	1174.8	1188.8	1078.1	888.8	748.8
4	1186.4	1082.2	888.8	883.4	488.8
5	1078.4	888.8	748.8	488.8	333.8

t=200 days

Table 1 (cont.)

J/I	1	2	3	4	5
1	4104.6	3934.6	2386.6	1387.6	1385.0
2	3934.6	3218.2	1344.6	1383.6	1328.6
3	2386.6	1344.6	1378.2	1382.3	1171.6
4	1387.6	1383.6	1382.3	1122.8	880.3
5	1385.0	1328.6	1171.6	880.3	494.2

J/I	1	2	3	4	5
1	3670.1	2068.6	1384.6	1381.4	1345.6
2	2068.6	1386.6	1383.6	1381.6	1238.6
3	1384.6	1383.6	1373.1	1186.2	1046.3
4	1381.4	1381.6	1186.2	863.0	782.1
5	1345.6	1238.6	1046.3	782.1	433.4

t=226 days

J/I	1	2	3	4	5
1	4105.8	3961.4	3081.6	1484.6	1483.3
2	3961.4	3454.0	1482.4	1481.8	1431.6
3	3081.6	1482.4	1458.6	1446.2	1319.6
4	1484.6	1481.8	1446.2	1278.1	1058.6
5	1483.3	1431.6	1319.6	1058.6	646.7

J/I	1	2	3	4	5
1	3730.6	2481.6	1482.6	1480.2	1480.8
2	2481.6	1484.0	1481.4	1470.6	1267.1
3	1482.6	1481.4	1474.4	1318.8	1184.6
4	1480.2	1470.6	1318.8	1094.2	886.6
5	1480.8	1267.1	1184.6	886.6	801.7

t=250 days

J/I	1	2	3	4	5
1	4107.7	3886.7	3493.3	1705.8	1704.8
2	3886.7	3678.4	1707.1	1705.7	1688.4
3	3493.3	1707.1	1706.2	1695.6	1626.0
4	1705.8	1705.7	1695.6	1618.2	1348.1
5	1704.8	1688.4	1626.0	1348.1	820.8

J/I	1	2	3	4	5
1	3816.3	3081.3	1722.4	1720.1	1711.0
2	3081.3	1724.4	1723.1	1716.7	1627.1
3	1722.4	1723.1	1716.2	1613.7	1466.0
4	1720.1	1716.7	1613.7	1404.4	1183.7
5	1711.0	1627.1	1466.0	1183.7	708.1

t=300 days

J/I	1	2	3	4	5
1	4105.8	3961.4	3081.6	1484.6	1483.3
2	3961.4	3454.0	1482.4	1481.8	1431.6
3	3081.6	1482.4	1458.6	1446.2	1319.6
4	1484.6	1481.8	1446.2	1278.1	1058.6
5	1483.3	1431.6	1319.6	1058.6	646.7

J/I	1	2	3	4	5
1	3862.2	3298.1	2006.7	2005.6	2003.7
2	3298.1	2006.4	2006.7	2002.8	1887.8
3	2006.7	2006.7	1889.0	1845.7	1649.1
4	2005.6	2003.8	1845.7	1805.7	1535.2
5	2003.7	1887.8	1649.1	1535.2	924.4

t=350 days

J/I	1	2	3	4	5
1	4108.8	4003.3	3885.8	1885.1	1900.2
2	4003.3	3809.6	3156.3	1883.1	1897.7
3	3885.8	3156.3	1883.3	1882.4	1881.2
4	1885.1	1883.1	1882.4	1858.0	1826.7
5	1900.2	1897.7	1881.2	1826.7	1316.4

J/I	1	2	3	4	5
1	3874.8	3421.6	1863.8	1862.6	1862.4
2	3421.6	1863.8	1863.0	1861.7	1850.7
3	1863.6	1863.0	1857.6	1849.8	1674.8
4	1862.8	1861.7	1849.8	1852.1	1831.2
5	1862.4	1850.7	1674.8	1831.2	1013.6

t=385 days

J/I	1	2	3	4	5
1	4108.7	4002.0	3874.8	1845.8	1847.3
2	4002.0	3802.8	3124.1	1843.8	1844.6
3	3874.8	3124.1	1834.4	1833.4	1831.4
4	1845.8	1843.8	1833.4	1811.0	1881.4
5	1847.3	1844.6	1831.8	1881.4	1285.6

J/I	1	2	3	4	5
1	3670.4	3388.4	2000.7	1888.7	1888.0
2	3388.6	2000.6	2000.1	1886.6	1881.6
3	2000.7	2000.1	1884.3	1885.8	1887.3
4	1888.7	1884.6	1885.8	1888.6	1840.7
5	1888.0	1881.6	1887.3	1840.7	1013.3

t=402 days

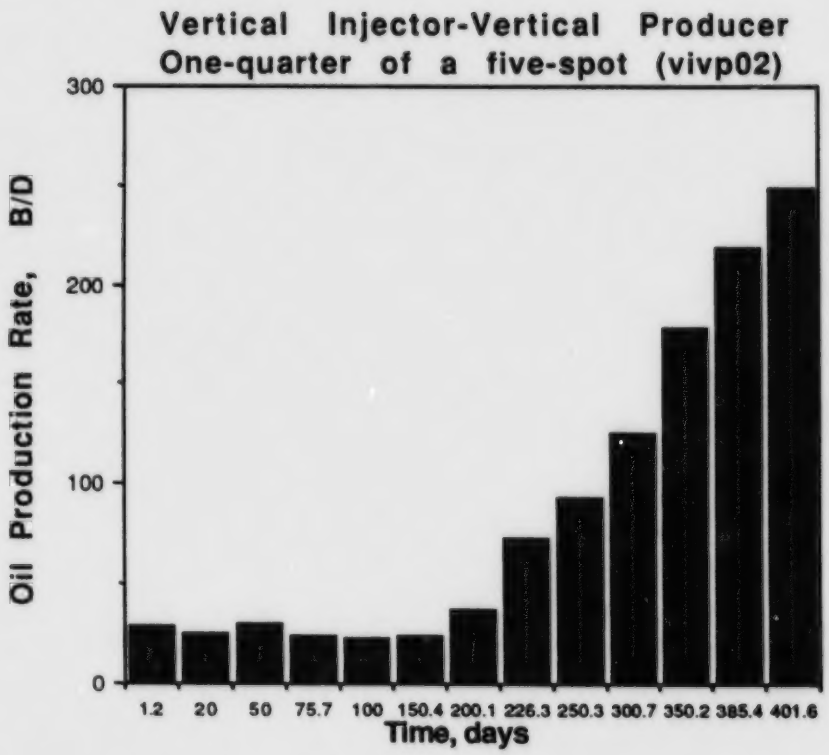


Fig. 1 - Oil Production Rate vs. Time for a Vertical Injector and a Vertical Injector and a Vertical Producer.

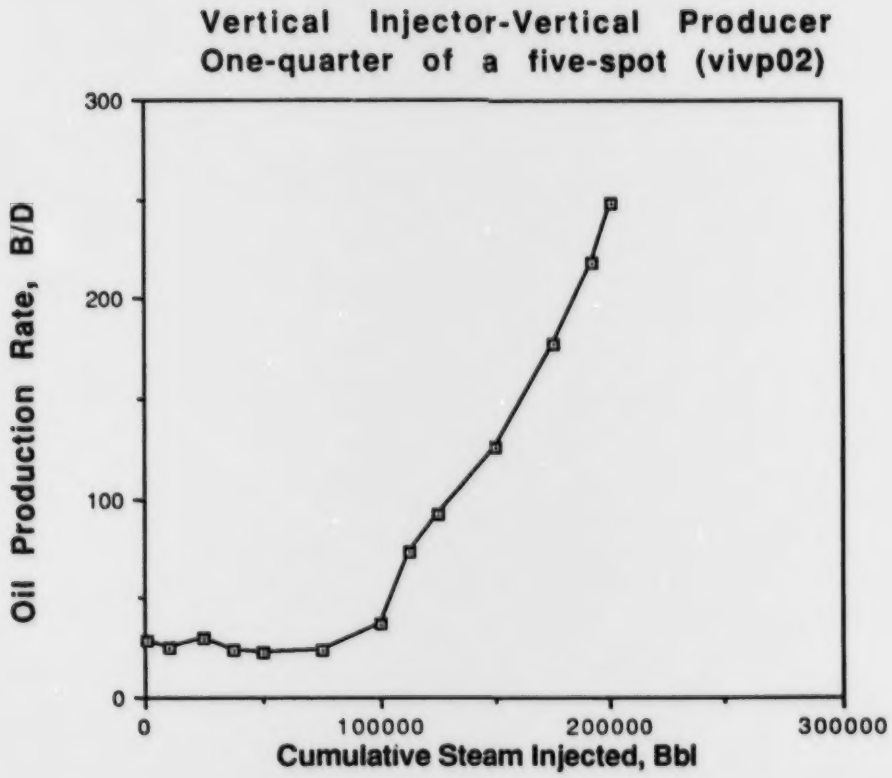


Fig. 2 - Oil Production Rate vs. Cumulative Steam Injected for a Vertical Injector and a Vertical Producer.

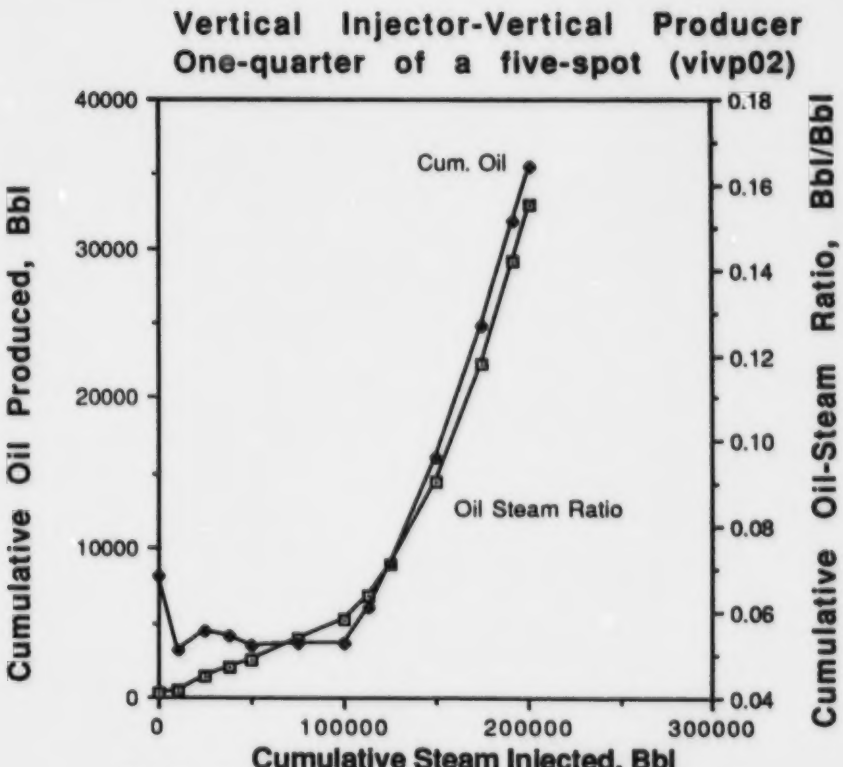


Fig. 3 - Cumulative Oil and Oil-Steam Ratio vs. Cumulative Steam Injected for a Vertical Injector and a Vertical Producer.

COMBINATION RUNS
Task 6

The objective of this part of the study was to determine which horizontal-vertical well combinations offer promise for steamflooding. Eight runs were carried out for several situations; the highlights of these runs are discussed below. The results are summarized in Table 2.

In these runs, the pattern size was fixed at 2 ha (4.94 acres), and the steam injection rate was held constant at 250 B/D (cold water equivalent) per five-spot quadrant, regardless of the type or placement of the wells. The main variable studied was the type of well and where it is completed. The productivity index was adjusted to make allowance for the well lenghts, vertical or horizontal. Temperature was varied in a few runs. Both the steam injection and production wellbore (if horizontal producer) models were used.

An example of a run at a lower initial temperature is Run VIVP, employing a vertical injector and a vertical producer, and an initial temperature of 176°F (80°C). The oil production rate is shown in Fig. 4, while the oil production vs. cumulative injection and the oil-steam ratio plots are shown in Figs. 5 and 6, respectively. The oil production rate was about 15-20 B/D, with high water cuts (not shown). The oil-steam ratio was very low (Fig. 6), being below the 0.07 level, for the greater portion of the run.

Run VIHP01 utilized a vertical injector, completed in the lower layer, and a horizontal producer, completed in the lower layer also. (Please see Table 2 for the well configuration used). The oil production rate is shown in Fig. 7, while the oil production vs. cumulative injection and the oil-steam ratio plots are shown in Figs. 8 and 9, respectively. The contrast with the previous run is striking: the oil production rate starts out at a low level as before, but increases steadily with time. This behaviour was evident in all runs employing horizontal wells. The oil-steam ratio (Fig. 9), though low, is seen to increase with time.

In Run VIHP02, the horizontal well was placed in the upper layer, all other parameters were same as in the run discussed above. The oil production rates start out at a low level (Fig. 10), but increase with time, as one would expect. The plots of oil production rate (Fig. 11) and oil-steam ratio (Fig. 12)

Table 2

Summary of the Runs Conducted Under Tasks 6 and 7

Run No.	Injector	in upper?	in lower?	Producer	in upper?	in lower?
VIVP	Vertical	Yes	Yes	Vertical	Yes	Yes
VIHP01	Vertical	No	Yes	Horiz.	No	Yes
VIHP02	Vertical	No	Yes	Horiz.	Yes	No
VIHP03	Vertical	No	Yes	Horiz.	Yes	Yes
HIHP01	Horiz.	No	Yes	Horiz.	No	Yes
HIHP02	Horiz.	No	Yes	Horiz.	No	Yes
HIHP03	Horiz.	Yes	No	Horiz.	Yes	No
HIHP03A	Horiz.	Yes	No	Horiz.	Yes	No
HIVP04	Horiz.	No	Yes	Vertical	Yes	Yes

Notes:
Pattern size in all runs was 2 ha (4.94 acres), with steam injection rate of 250 B/D (CWE) per quadrant. Formation temperature in the first two runs was 80°C, in the remaining runs it was 100°C. Injection wellbore was simulated in all runs, except in HIHP02/843628, in a constant quality was assumed for all injection blocks.

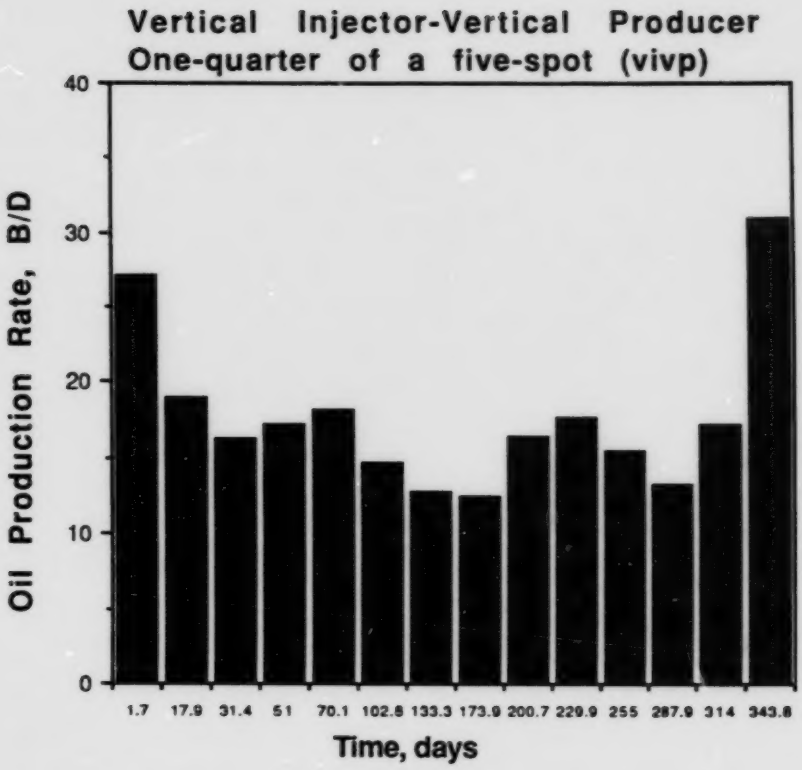


Fig. 4 - Oil Production Rate vs. Time for a Vertical Injector and a Vertical Producer.

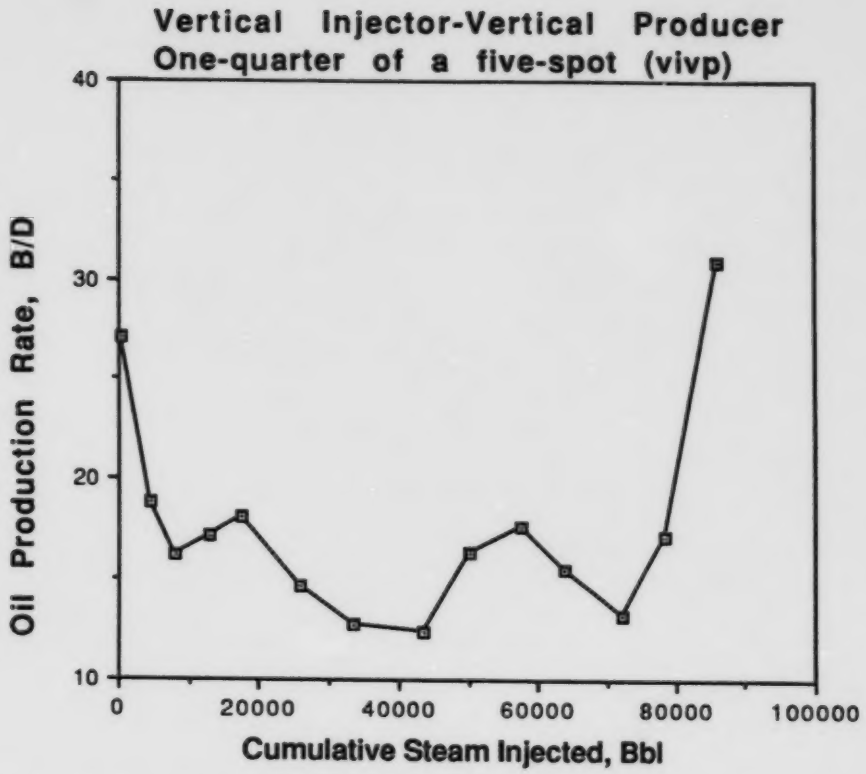


Fig. 5 - Oil Production Rate vs. Cumulative Steam Injected for a Vertical Injector and a Vertical Producer.

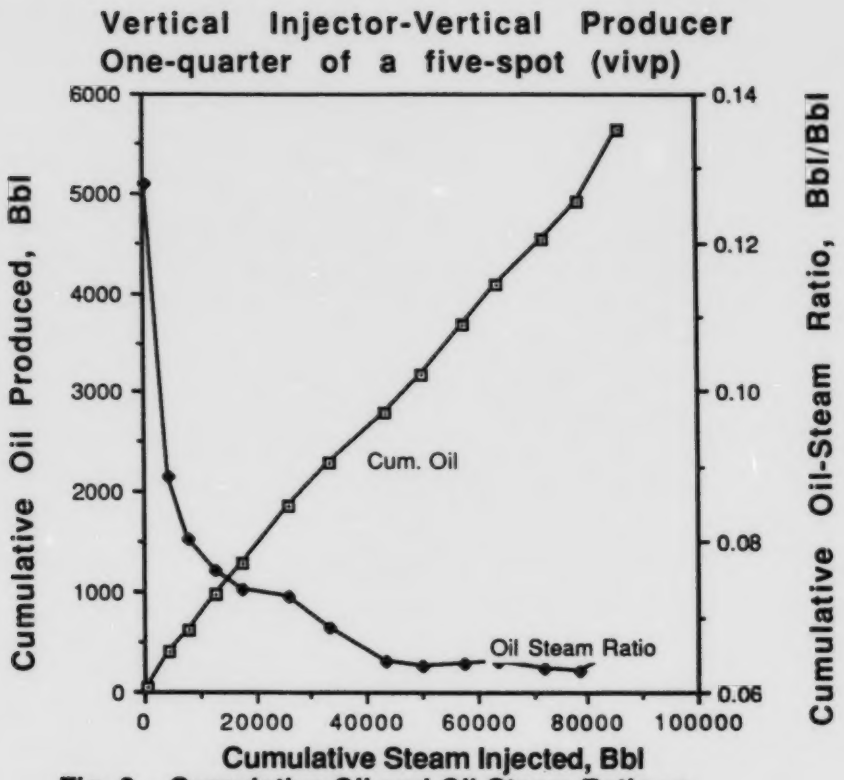


Fig. 6 - Cumulative Oil and Oil-Steam Ratio vs. Cumulative Steam Injected for a Vertical Injector and Vertical Producer.

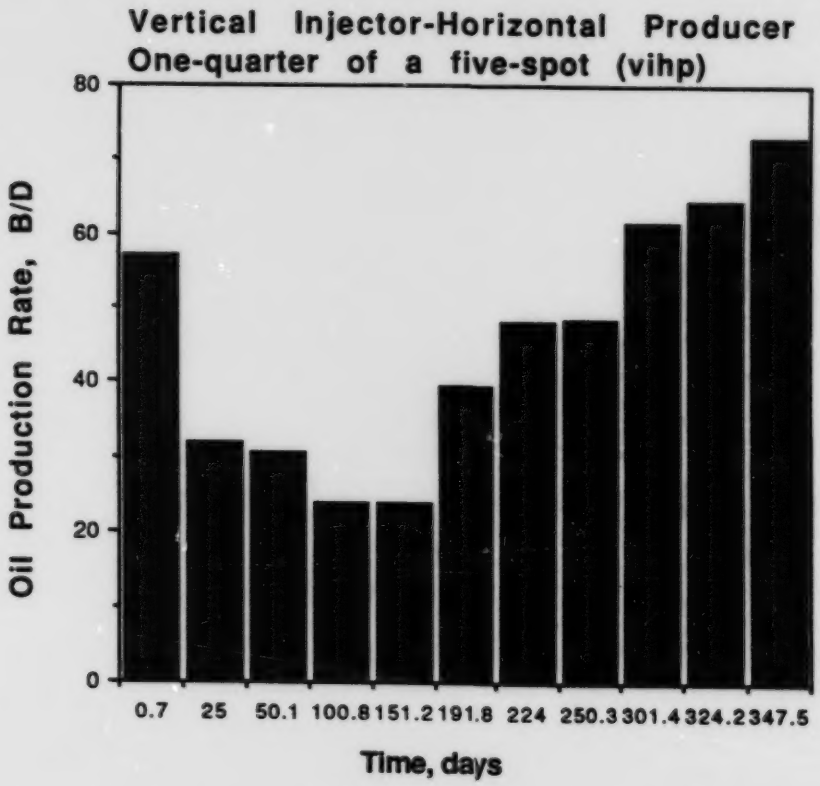


Fig. 7 - Oil Production Rate vs. Time for a Vertical Injector and a Horizontal Producer.

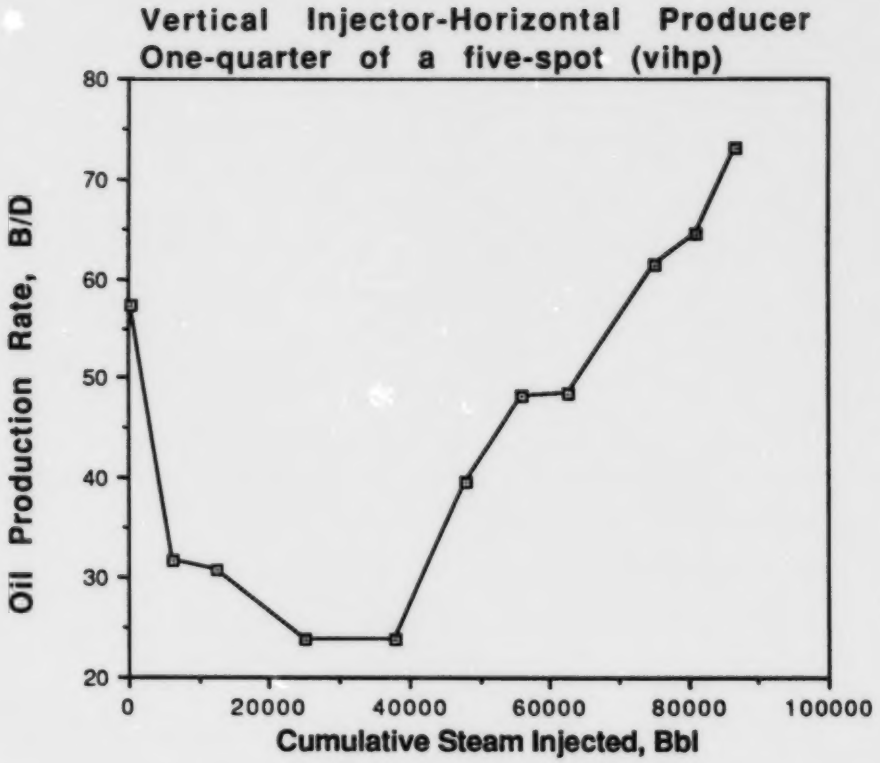


Fig. 8 - Oil Production Rate vs. Cumulative Steam Injected for a Vertical Injector and a Horizontal Producer.

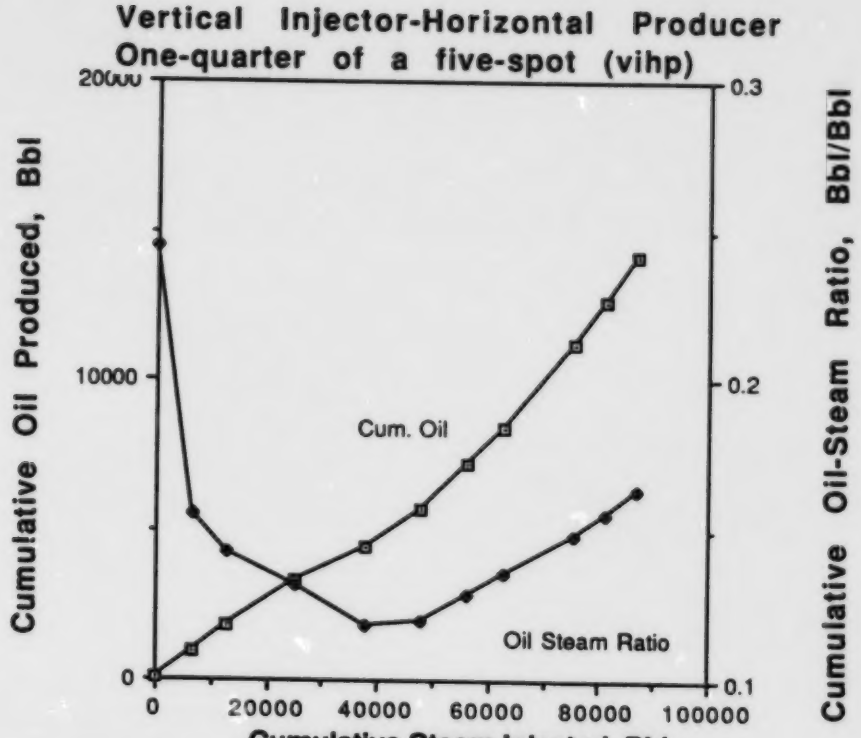


Fig. 9 - Cumulative Oil and Oil-Steam Ratio vs. Cumulative Steam Injected for a Vertical Injector and a Horizontal Producer.

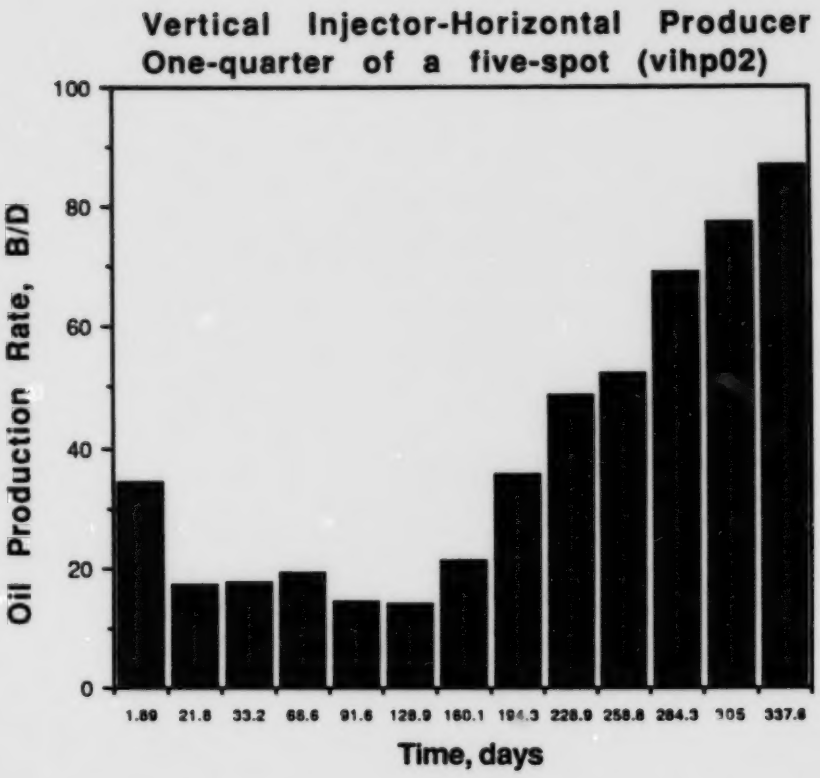


Fig. 10 - Oil Production Rate vs. Time for a Vertical Injector and a Horizontal Producer.

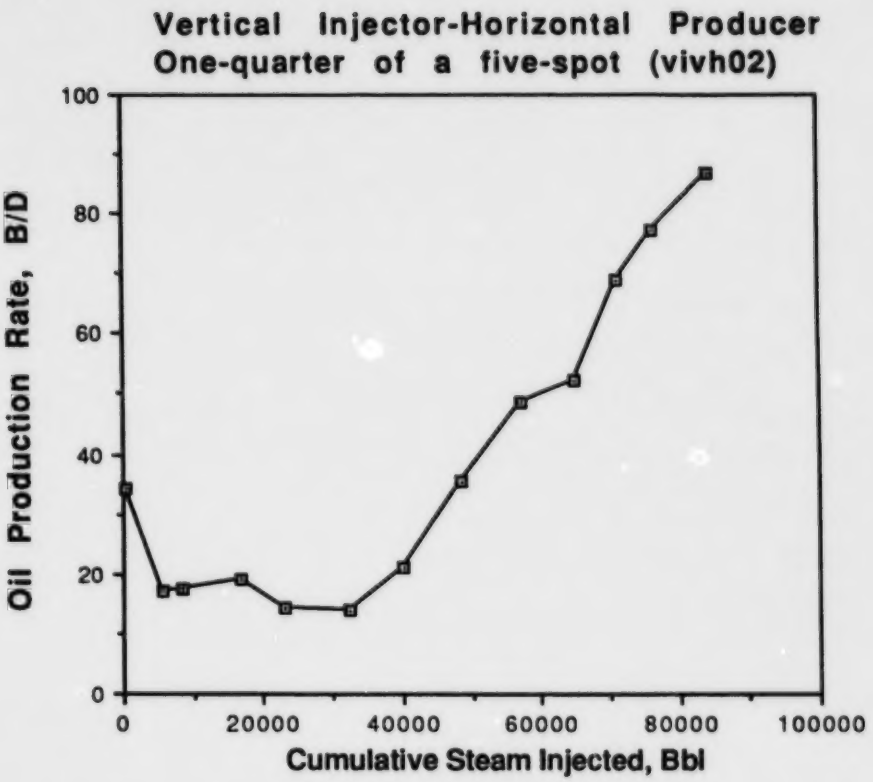


Fig. 11 - Oil Production Rate vs. Cumulative Steam Injected for a Vertical Injector and a Horizontal Producer.

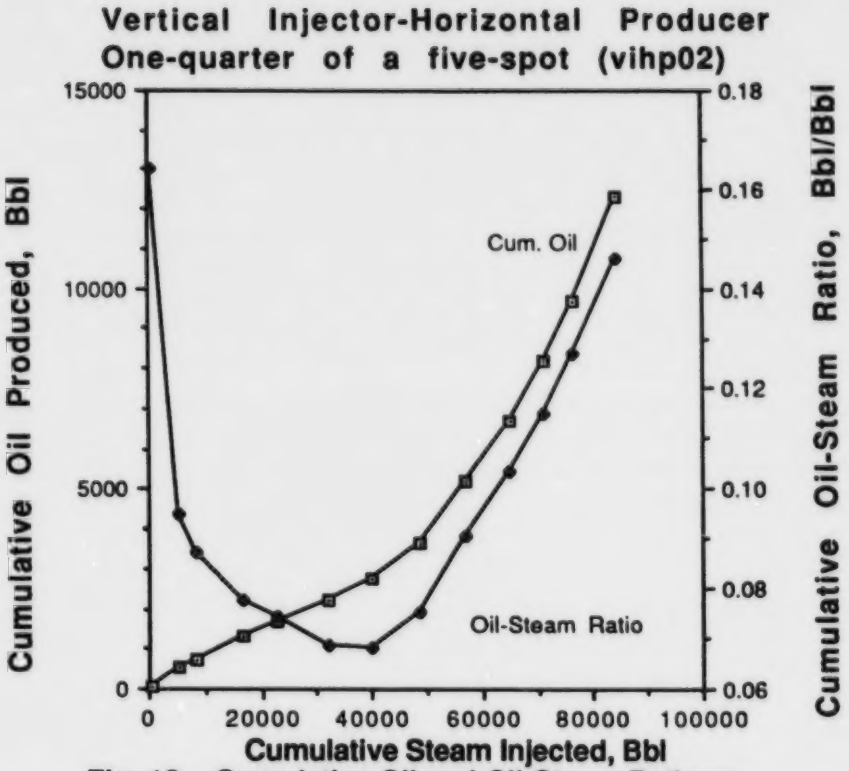


Fig. 12 - Cumulative Oil and Oil-Steam Ratio vs. Cumulative Steam Injected for a Vertical Injector and a Horizontal Producer.

show the gain with increased steam injection. However, even in this case the oil-steam ratio is still low, after a year of steam injection. The time step size in this run was, on the average, one-half of that in the previous run.

Run VIHP03 was an interesting variation on the previous run, with the horizontal well placed in *both* layers. The production history is shown in Fig. 13; the rates are distinctly higher than those shown in Fig. 10, however, the gain is not large enough to justify the drilling of two horizontal wells. Figure 14 shows the oil rate as a function of cumulative steam injected, while Fig. 15 shows the oil-steam ratio. This is still below 0.2, but is certainly an improvement on the previous runs.

Run HIHP01 is the first run employing a horizontal *injector* as well as a horizontal producer. The oil production rate is shown in Fig. 16, while the oil production vs. cumulative injection and the oil-steam ratio plots are shown in Figs. 17 and 18, respectively. Both wells are placed in the lower layer. It is clear that the oil production rate is higher, and the oil-steam ratio increases rapidly with time. More important, the injection pressures were considerably lower in this run. Table 3 shows selected values of the injection pressures. Because the total injection rate is spread over a greater area, the pressures are moderate.

In the previous runs, a variable steam quality at the injection well was employed; in other words, the injection well model was activated to supply the steam quality and pressure at each injection block. Run HIHP02 was designed to examine the effect of a constant quality at all injection blocks (i.e. no injection well simulation), as done in the conventional approach to horizontal injector simulation. The results for this run are shown in Figs. 19,20, and 21. The overall performance is definitely better than that for the previous variable quality case. The oil production rates are higher than those in Fig. 16. Care should be taken to compare the rates for the same times. (The arrow in Fig. 19 indicates the last time value for the previous run). At the similar times, the cumulative oil produced was 55,332 Bbl for this run, compared to 34,000 Bbl for the variable quality case. It is thus seen that using a constant steam quality may lead to optimistic recovery figures.

Runs HIHP03 and HIHP03A were conducted to see the effect of both horizontal injector and producer in the upper layer, but in the first run injection was also included in the lower layer in the first block only, to see how much difference such a perturbation would make. Figures 22-24 and 25-27 present

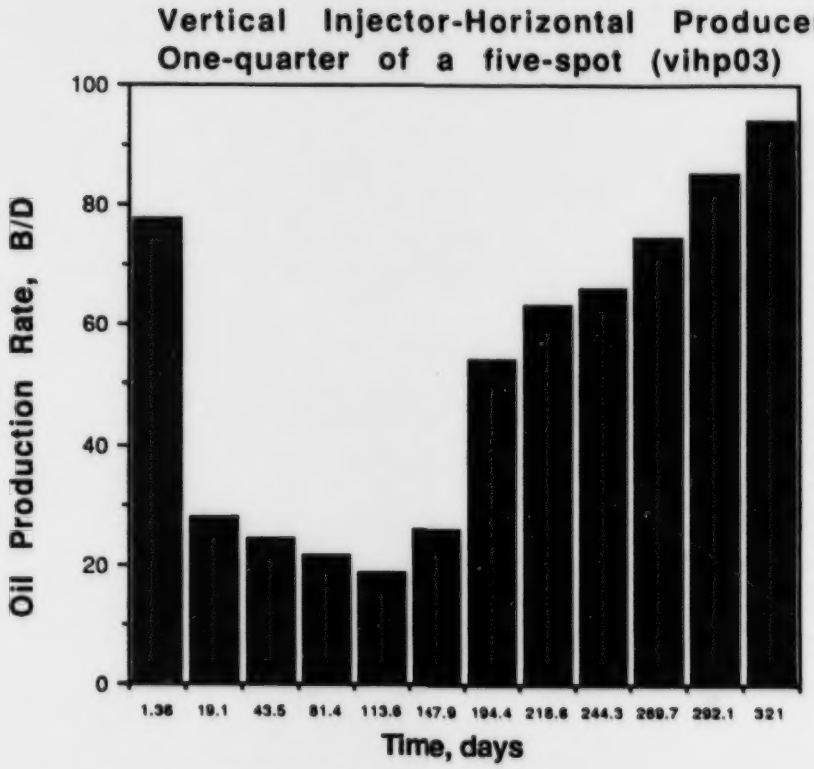


Fig. 13 - Oil Production Rate vs. Time for a Vertical Injector and a Horizontal Producer.

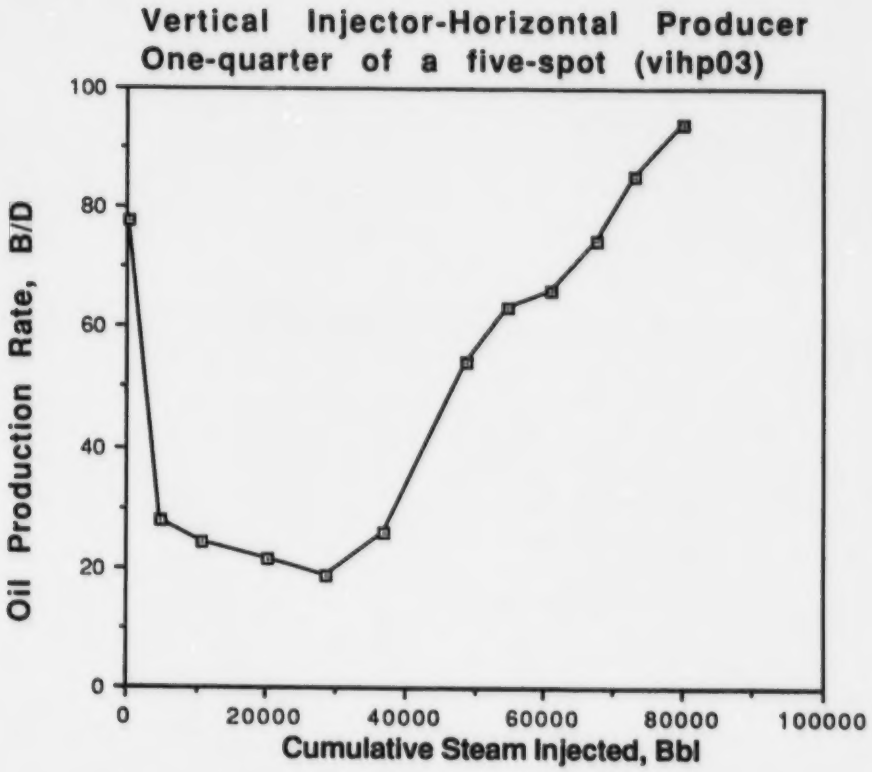


Fig. 14 - Oil Production Rate vs. Cumulative Steam Injected for a Vertical Injector and a Horizontal Producer.

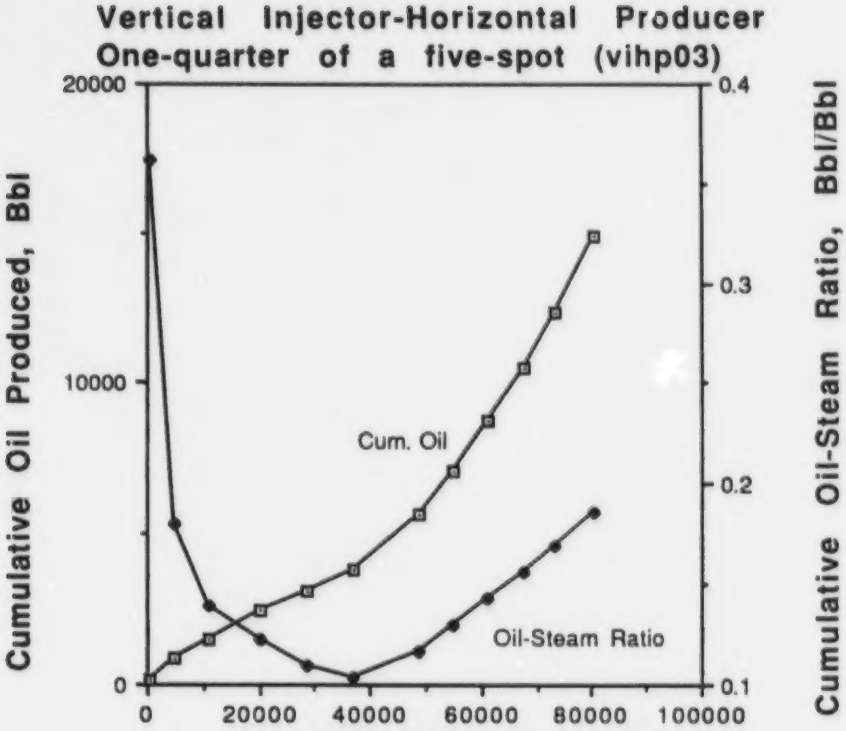


Fig. 15 - Cumulative Oil and Oil-Steam Ratio vs. Cumulative Steam Injected for a Vertical Injector and a Horizontal Producer.

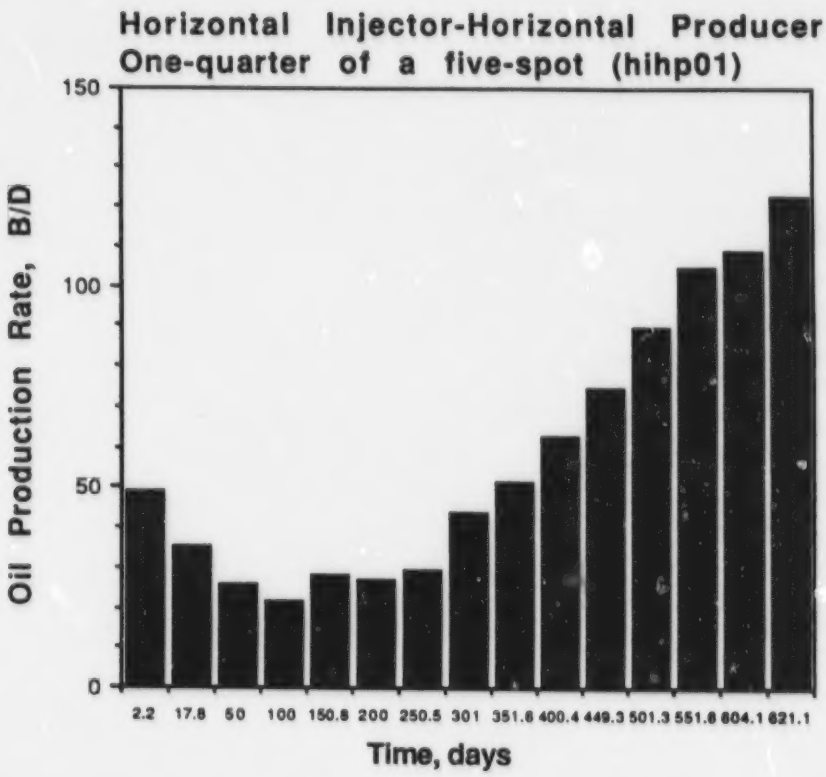


Fig. 16 - Oil Production Rate vs. Time for a Horizontal Injector and a Horizontal Producer.

Fig. 17 - Oil Production Rate vs. Cumulative Steam Injected for a Horizontal Injector and a Horizontal Producer.

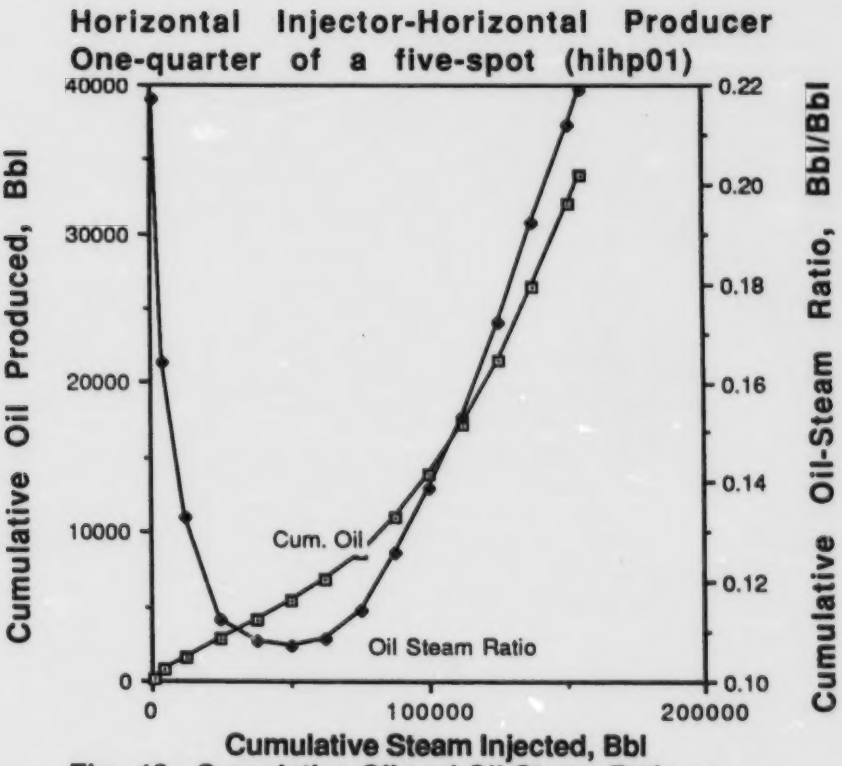


Fig. 18 - Cumulative Oil and Oil-Steam Ratio vs. Cumulative Steam Injected for a Horizontal Injector and a Horizontal Producer.

Table 3

Selected Values of Injection Pressure in the Injection Blocks (1,1,1) and (1,1,2) in Run HIHP01

Time, days	Pressure at (1,1,1),psi	Pressure at (1,1,2),psi
2	349	419
18	265	361
50	218	279
100	211	250
150	297	563
200	345	1090
352	451	2900
552	628	3316
643	588	3407

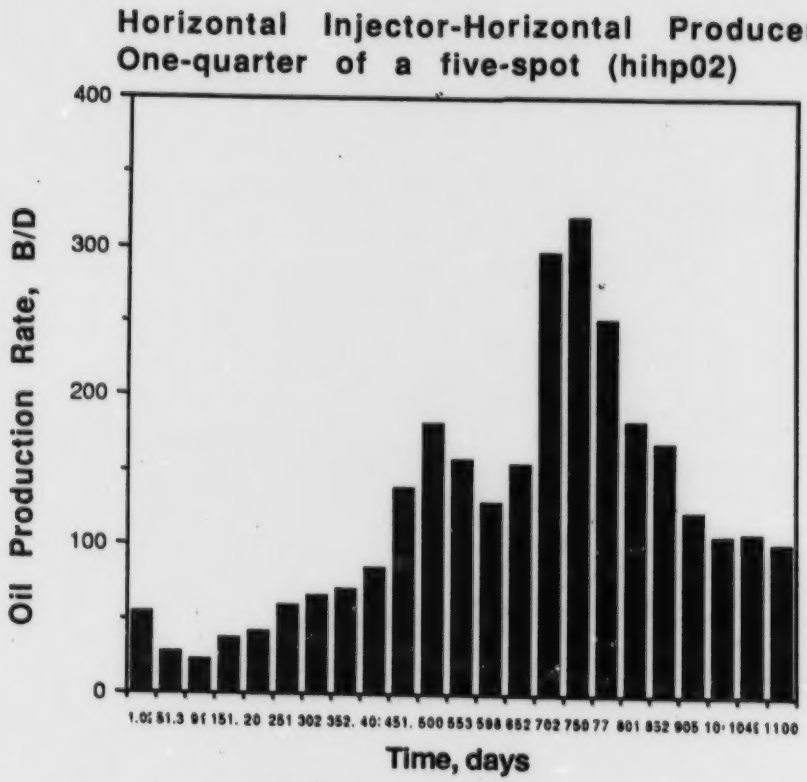


Fig. 19 - Oil Production Rate vs. Time for a Horizontal Injector and a Horizontal Producer.

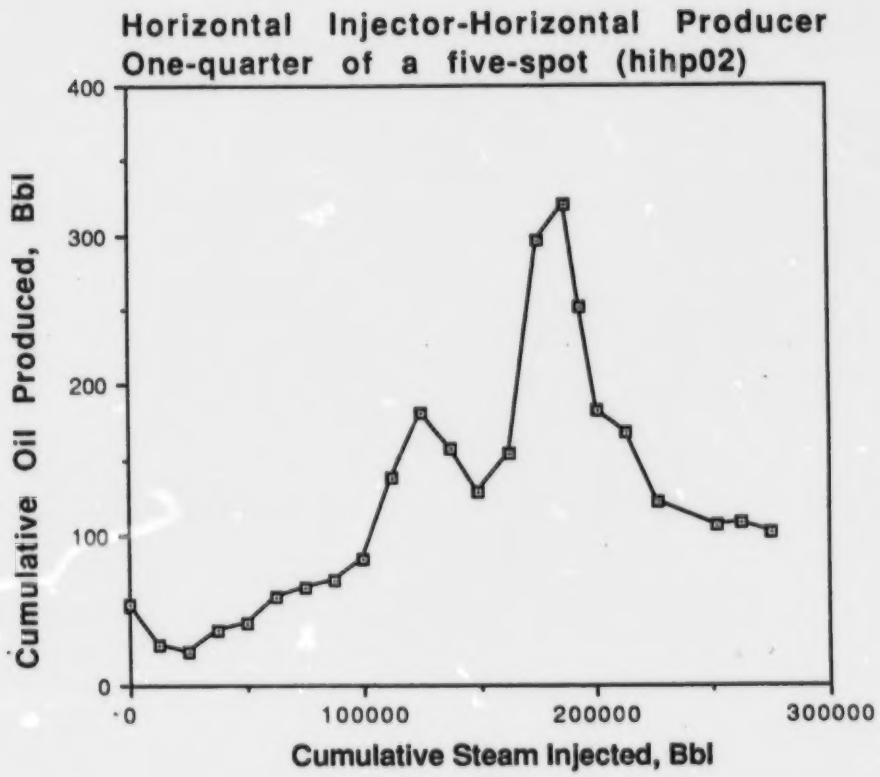


Fig. 20 - Oil Production Rate vs. Cumulative Steam Injected for a Horizontal Injector and a Horizontal Producer.

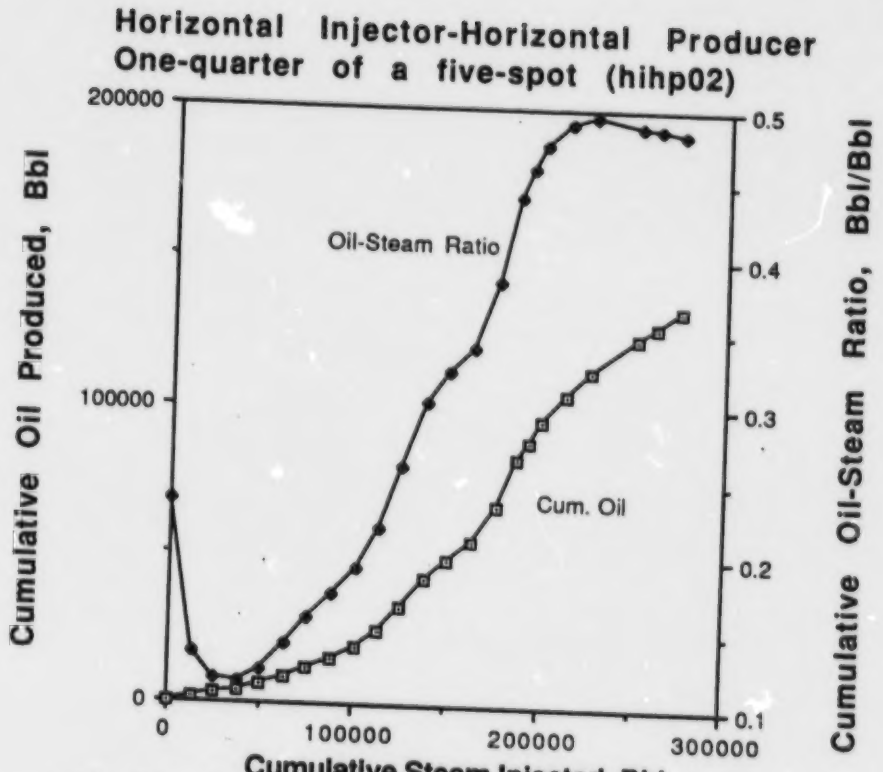


Fig. 21 - Cumulative Oil and Oil-Steam Ratio vs. Cumulative Steam Injected for a Horizontal Injector and a Horizontal Producer.

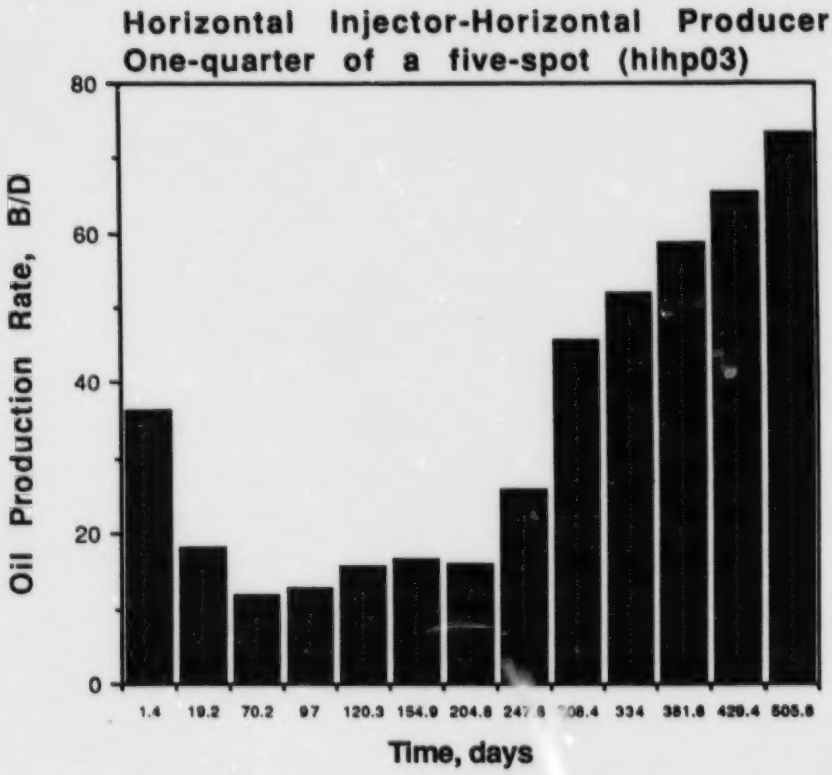


Fig. 22 - Oil Production Rate vs. Time for a Horizontal Injector and a Horizontal Producer.

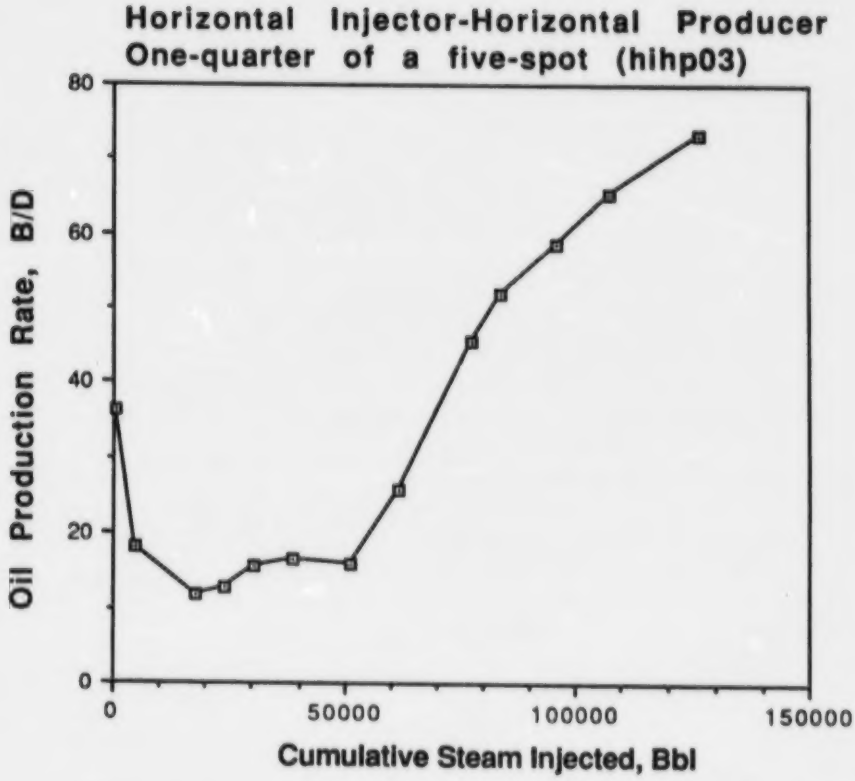


Fig. 23 - Oil Production Rate vs. Cumulative Steam Injected for a Horizontal Injector and a Horizontal Producer.

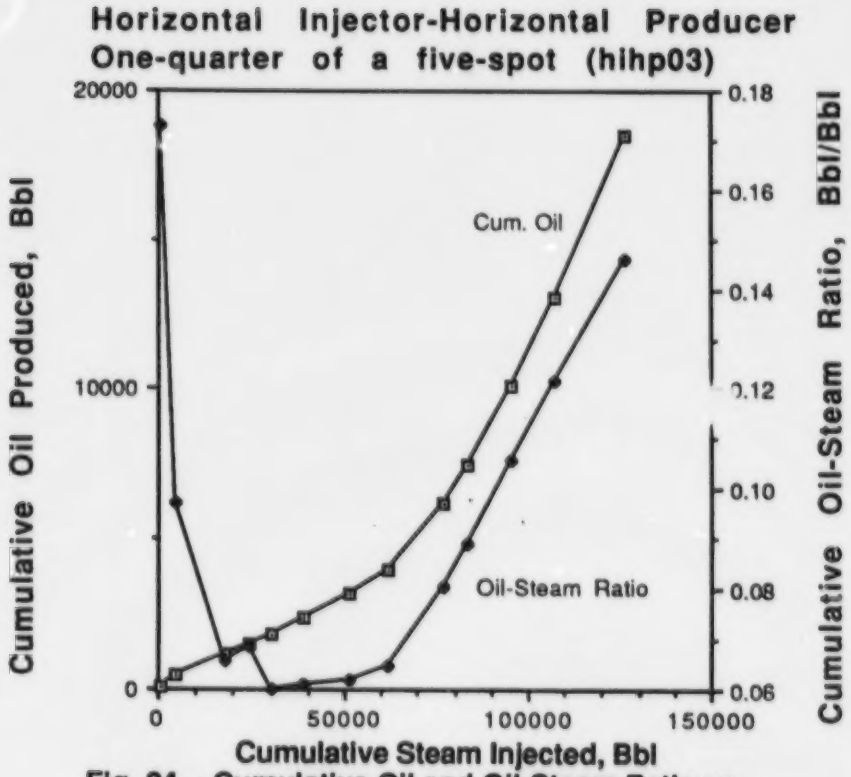


Fig. 24 - Cumulative Oil and Oil-Steam Ratio vs. Cumulative Steam Injected for a Horizontal Injector and a Horizontal Producer.

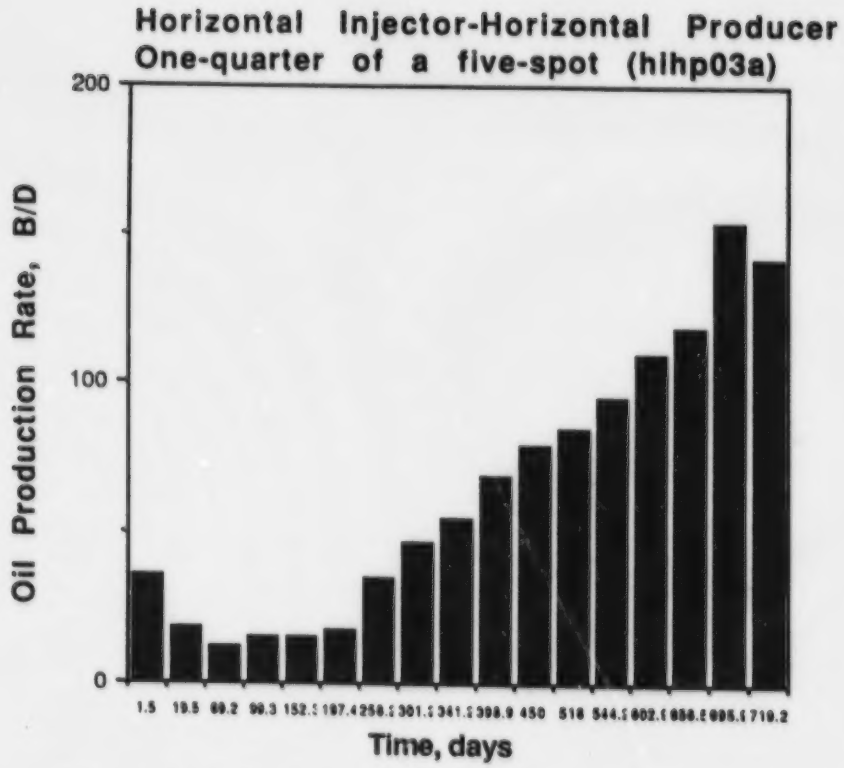


Fig. 25 - Oil Production Rate vs. Time for a Horizontal Injector and a Horizontal Producer.

Fig. 26 - Oil Production Rate vs. Cumulative Steam Injected for a Horizontal Injector and a Horizontal Producer.

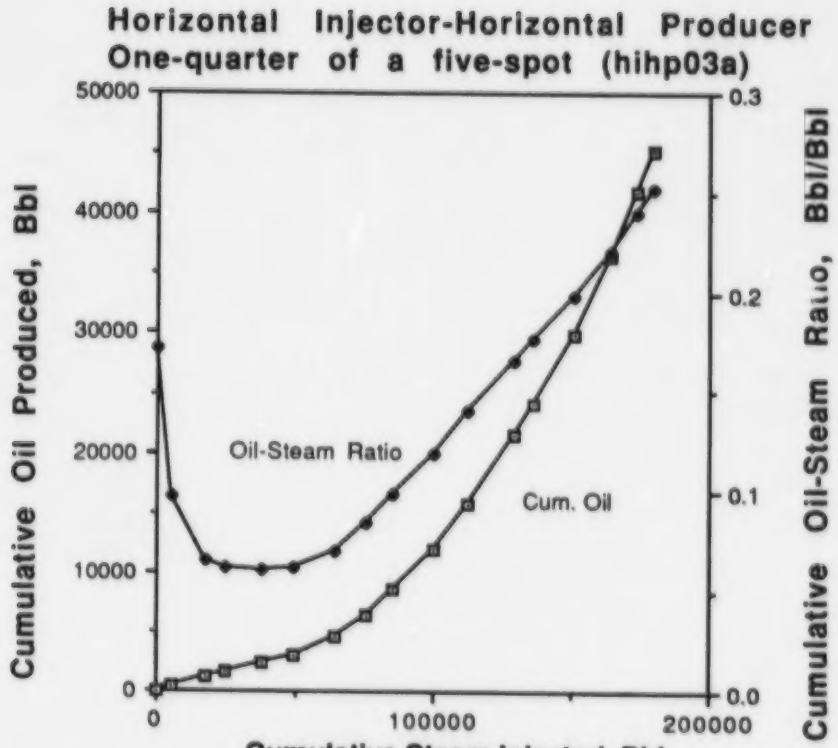


Fig. 27 - Cumulative Oil and Oil-Steam Ratio vs. Cumulative Steam Injected for a Horizontal Injector and a Horizontal Producer.

similar plots for the two runs. It is interesting to note that the additional steam injection in the first run had an adverse effect on performance. This is particularly evident from the oil-steam ratio plots (Figs. 24 and 27).

Run HIVP04 utilized a horizontal injector, in the lower layer, as in the above runs, but a vertical producer completed in both layers. The reason for this arrangement is simply that it is more of a problem injecting steam into the formation, and possibly, in some instances a vertical producer may be adequate. The oil production plot is shown in Fig. 28, the oil rate vs. cumulative steam plot in Fig. 29, and the oil-steam ratio plot in Fig. 30. It is clear that the production performance in this case was better than in the other instances. In particular, the oil-steam ratio increased to about 0.3, and stayed at this level. The vertical well performance is better than expected, partly because of the large thickness. Furthermore, the lower vertical permeability is not particularly favourable to horizontal wells.

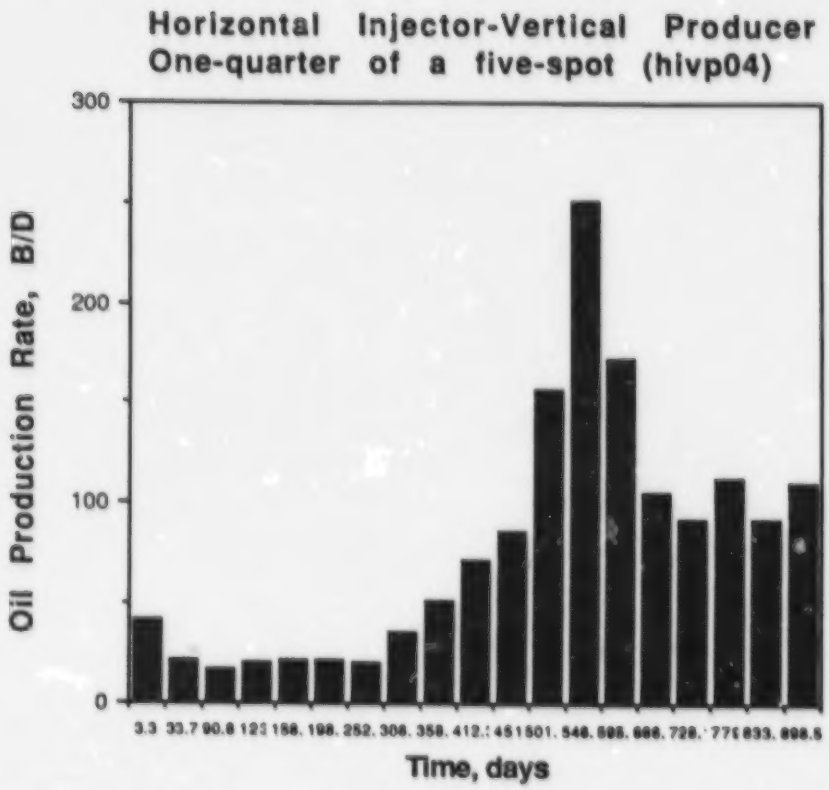

Horizontal Injector-Vertical Producer
One-quarter of a five-spot (hivp04)
Oil Production Rate, B/D
300
200
100
0
3.3 33.7 90.8 123 158. 198. 252. 308. 358. 412. 451 501. 548. 598. 668. 728. 778 833. 898.5
Time, days

Fig. 28 - Oil Production Rate vs. Time for a Horizontal Injector and a Vertical Producer.

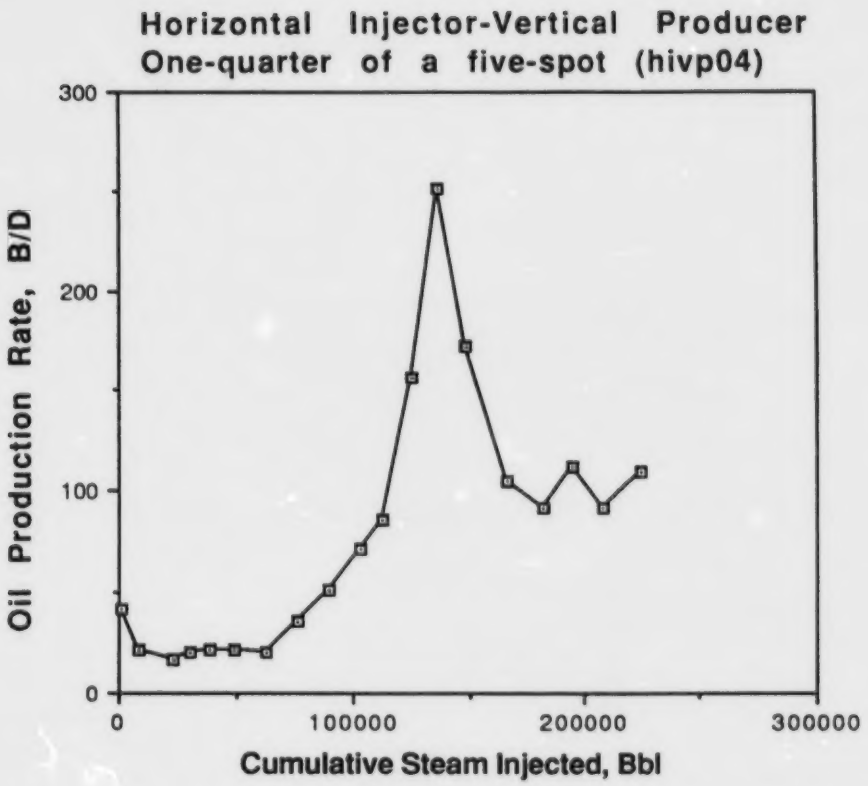


Fig. 29 - Oil Production Rate vs. Cumulative Steam Injected for a Horizontal Injector and Vertical Producer.

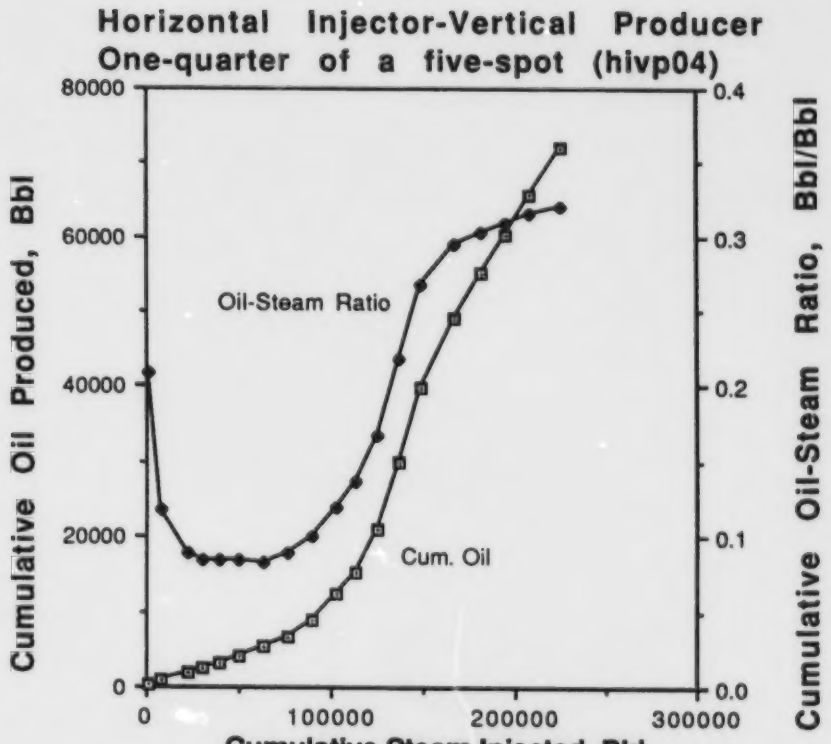


Fig. 30 - Cumulative Oil and Oil-Steam Ratio vs. Cumulative Steam Injected for a Horizontal Injector and Vertical Producer.

CONVENTIONAL MODEL vs. NEW MODEL
Task 7

The usual method for simulating vertical or horizontal wells consists in assigning a suitable productivity index to the well block, and calculating the inflow rate (in the case of a producer) using the block pressure and the well pressure. In the case of a steam injection well, steam intake into the different layers is often determined on the basis of layer capacities (kh), assuming the same steam quality for all layers. In neither case, the wellbore fluid flow is taken into account.

It was desired to determine how important is wellbore flow as far as horizontal or vertical well performance is concerned. Several runs were carried out. In the case of a producer, the difference was small, possibly because at the field rates of heavy oil production, the pressure drop is small, and the assumption of a constant flowing pressure vs. a pressure gradient in the wellbore makes only a small difference in the answer, even though three-phase flow in the wellbore is accounted for. (In the present runs, flow was only two-phase, since no gas was assumed to be produced). Figure 31 shows an example of the oil production rate plots, with and without the use of a comprehensive horizontal well model. However, this does not imply that a comprehensive model is not needed. It merely says that in the present runs, the flow rates were such that wellbore hydraulics were not predominant.

The situation is more defined in the case of an injection well. In the previous chapter, Run HIHP02 was designed to examine the effect of a constant quality at all injection blocks, as done in the conventional approach to horizontal well simulation. The results for this run were shown in Figs. 19,20, and 21. The overall performance is definitely better than that for the previous variable quality case, which is the more realistic of the two. The oil production rates are higher than those in Fig. 16. It can be concluded on the basis of the above runs - as well as many others not reported here - that the assumption of a constant quality at various injection points can lead to optimistic recovery estimates.

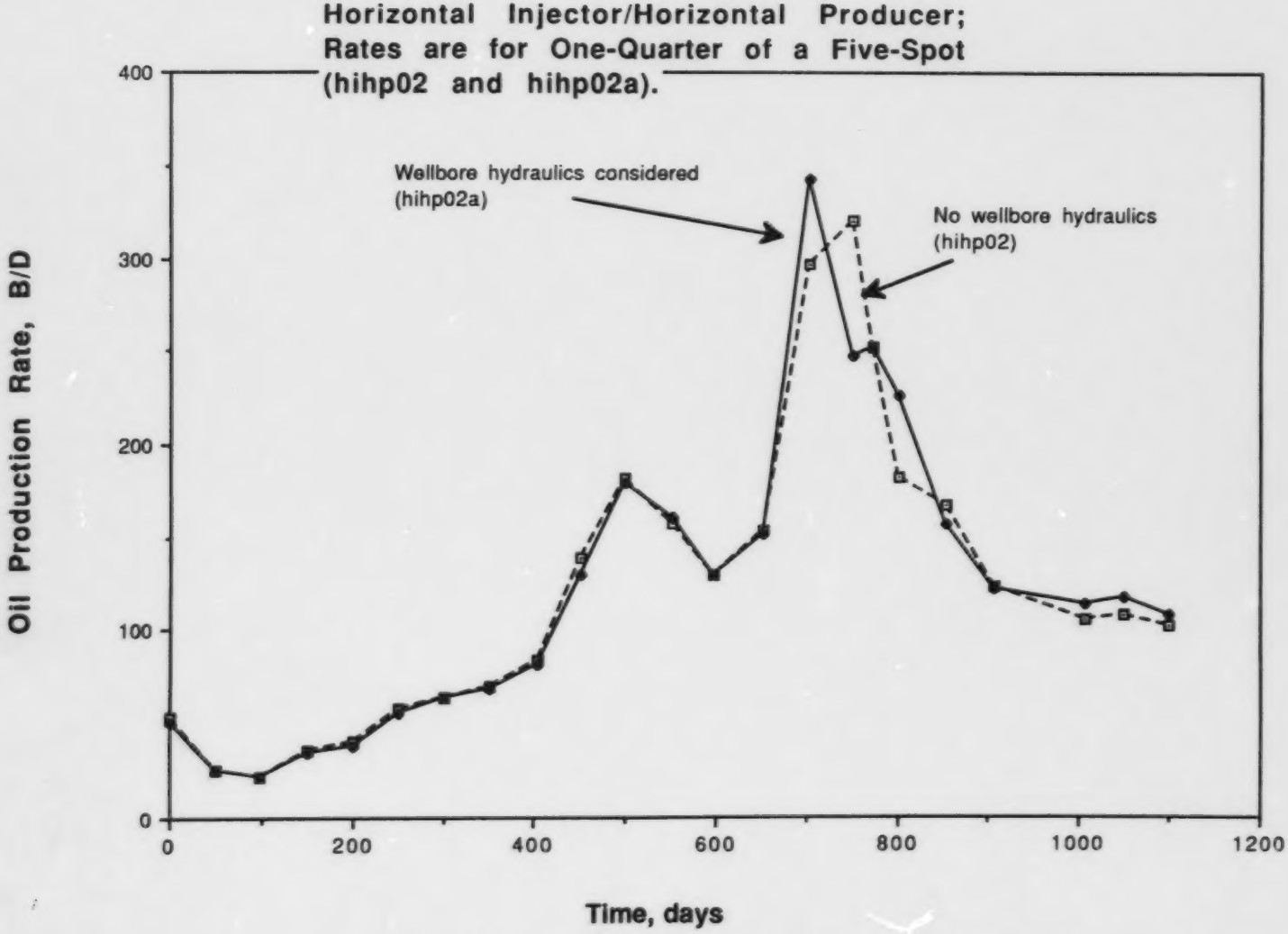


Fig. 31 - Effect of Production Well Hydraulics on Oil Production Rate.

HORIZONTAL/VERTICAL WELL RUNS
Task 8

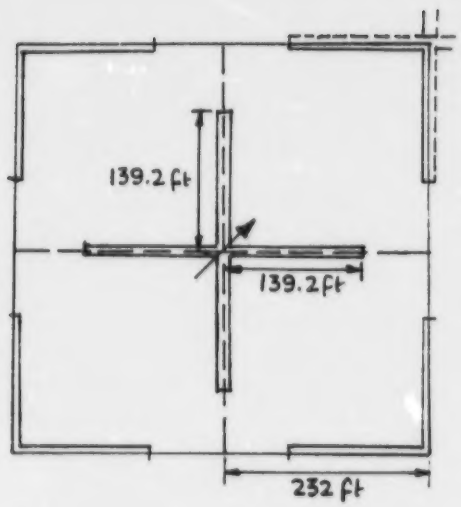
The purpose of this final series of runs was to determine which other combinations of horizontal and vertical wells are likely to be most effective in the field. The well configurations examined in this phase of this study are shown in Fig. 32. The horizontal wells in this case represent drainholes,extending over distances of about 150 ft, with four branches per well. Combinations of such wells are considered, in one case also with a vertical well. Two runs were repeated for the original formation temperature of 15°C.

Run PCSP01 was designed to simulate horizontal drainholes at both the injector and the producer, extending over three block lengths (139.2 ft), in the form of a cross. The injection drainholes were placed in both layers, while the producing drainholes were only in the bottom layer (Fig. 32). Pattern area and the operating conditions were the same as in the other runs, the quadrant steam injection rate being 250 B/D. Figures 33, 34, and 35 show the oil production rate with time, with cumulative steam, and the oil-steam ratio, respectively. It appears that this arrangement is very efficient, giving a high oil production rate and an oil-steam ratio averaging 0.2, which is typical of commercially successful steamfloods.

Run PCSP02 used the same conditions as the previous run, except that the horizontal drainholes were placed in the upper layer. The resulting performance curves are quite different, and are shown in Figs. 36 to 38. A comparison with the previous run shows that the oil production rate is more consistent rather than increasing sharply as in the previous run. Moreover, the total oil recovery is higher than that in the previous run.

Run PCSP03 again used the same conditions except that the drainholes were placed in the lower layer. The performance curves are shown in Figs. 39-41. In this case the oil recovery is distinctly higher than in the other two runs, in view of gravity flow. However the injection pressures were higher also, especially in the lower layer. In any case, this scheme yielded the largest amount of oil, and thus the highest oil-steam ratio.

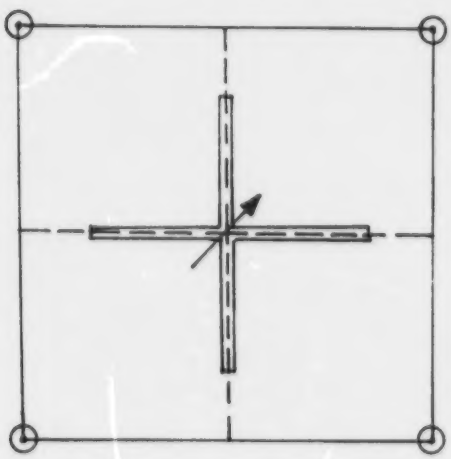
Run PCSP04 utilized a horizontal drainhole-vertical producer concept. Injection was into both layers through horizontal drainholes, while production was from a vertical well,



Run PCSP01
Injection into both layers, production from the lower layer.

Run PCSP02
As above, but production from upper layer.

Run PCSP03
Injection and production in the lower layer.



Run PCSP04
Injection into both layers, production from vertical well in lower layer only.

Fig. 32 - Well Configurations Used in the Special Runs (Task 8).

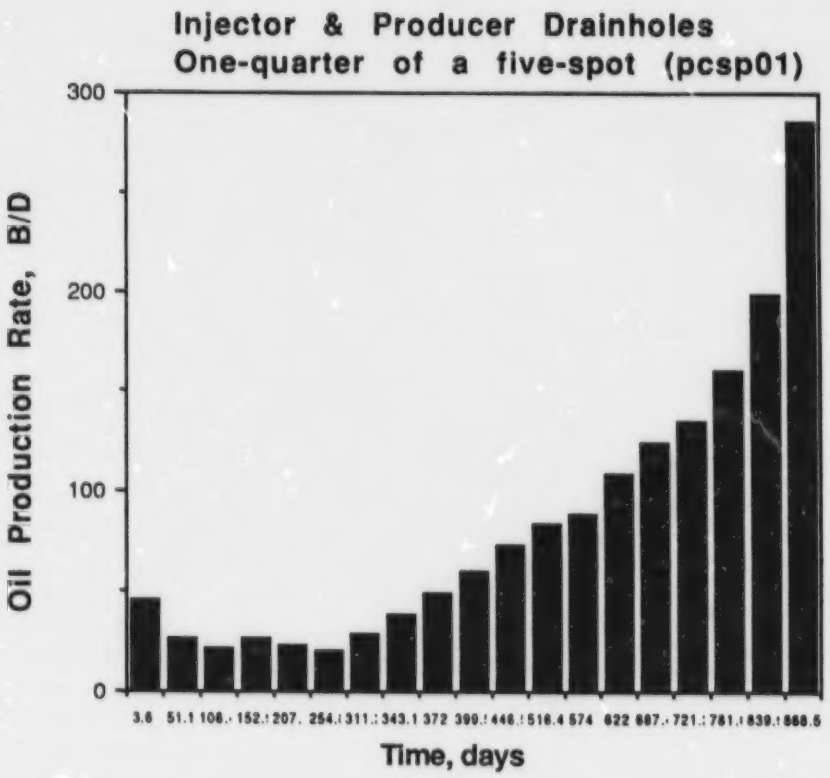

Injector & Producer Drainholes
One-quarter of a five-spot (pcsp01)
Oil Production Rate, B/D
300
200
100
0
3.6 51.1 108. 152. 207. 254. 311. 343.1 372 390. 446. 516.4 574 622 687. 721. 781. 839. 868.5
Time, days

Fig. 33 - Oil Production Rate vs. Time for a Injector and Producer Drainholes.

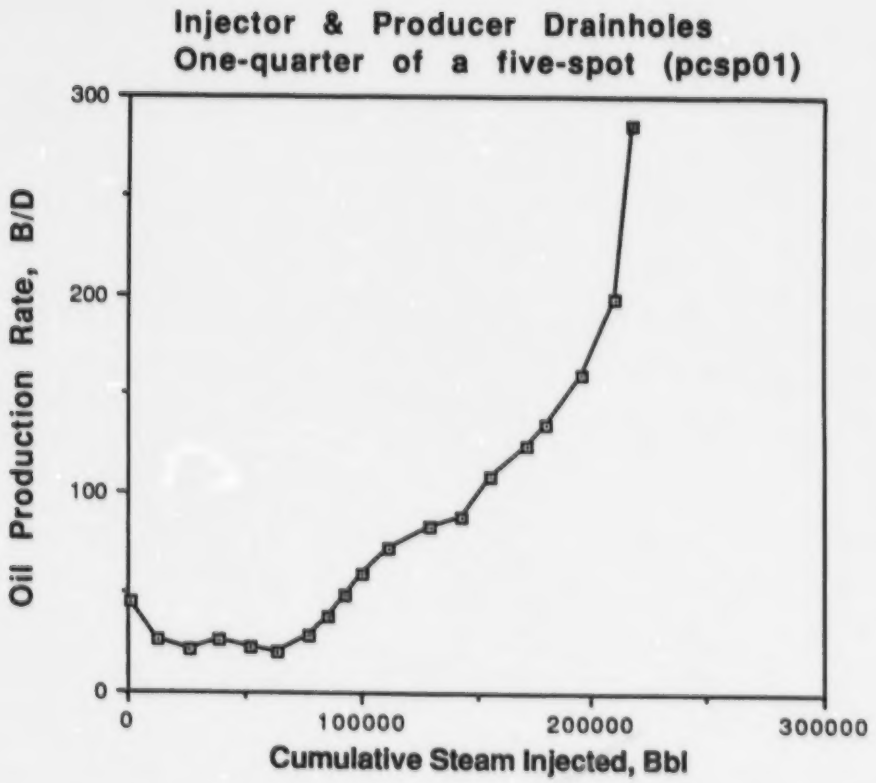


Fig. 34 - Oil Production Rate vs. Cumulative Steam Injected for Injector and Producer Drainholes.

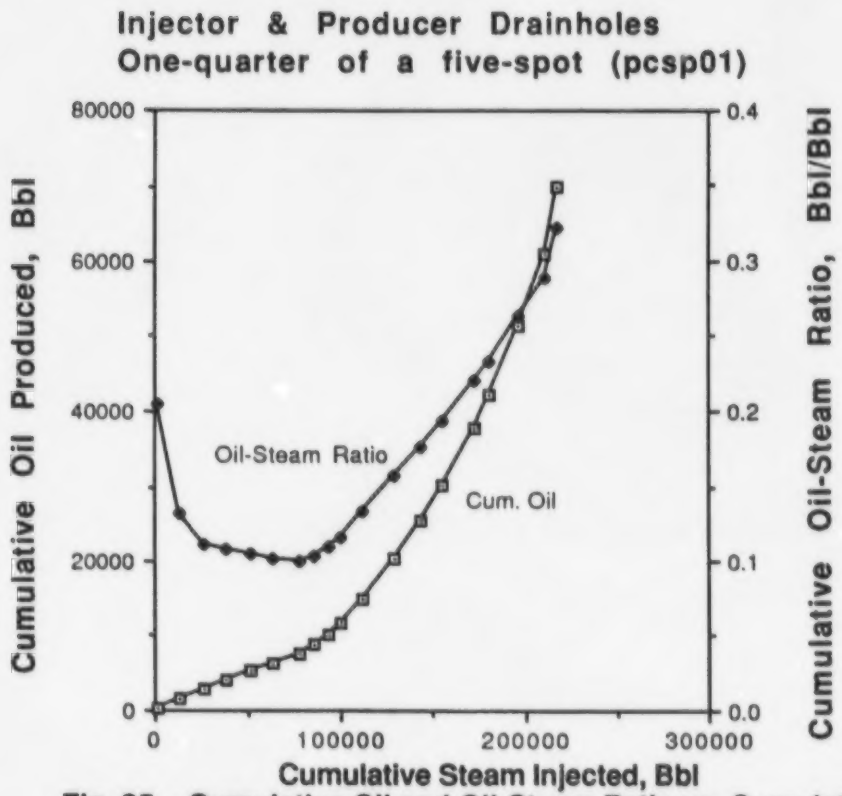


Fig. 35 - Cumulative Oil and Oil-Steam Ratio vs. Cumulative Steam Injected for Injector and Producer Drainholes.

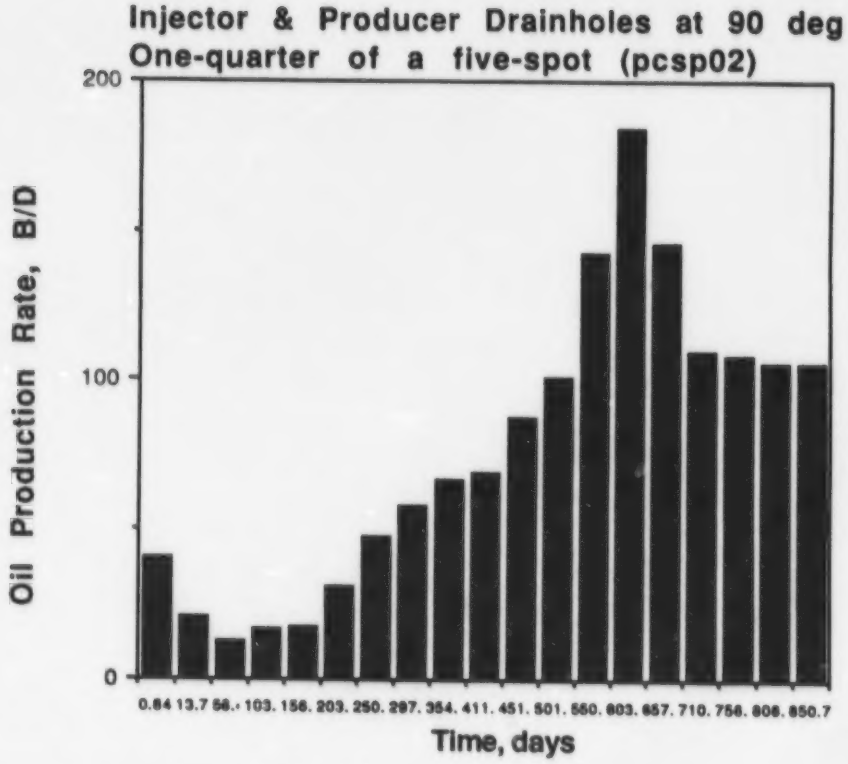

Injector & Producer Drainholes at 90 deg
One-quarter of a five-spot (pcsp02)
Oil Production Rate, B/D
200
100
0
0.84 13.7 56. 103. 156. 203. 250. 297. 354. 411. 451. 501. 550. 603. 657. 710. 756. 806. 850.7
Time, days

Fig. 36 - Oil Production Rate vs. Time for Injector and Producer Drainholes.

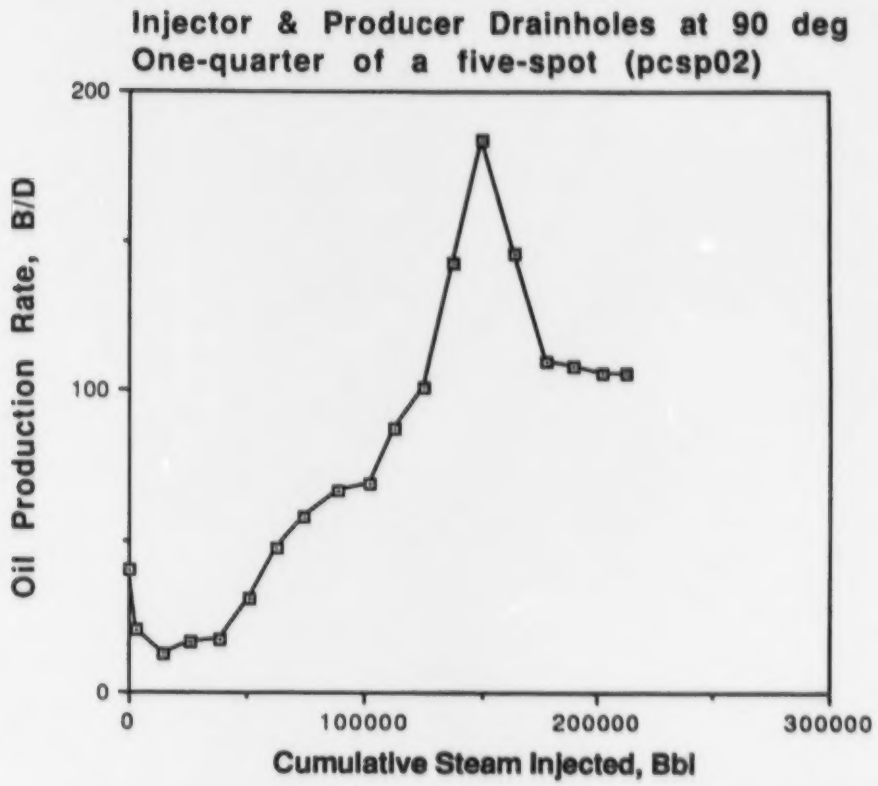


Fig. 37 - Oil Production Rate vs. Cumulative Steam Injected for Injector and Producer Drainholes.

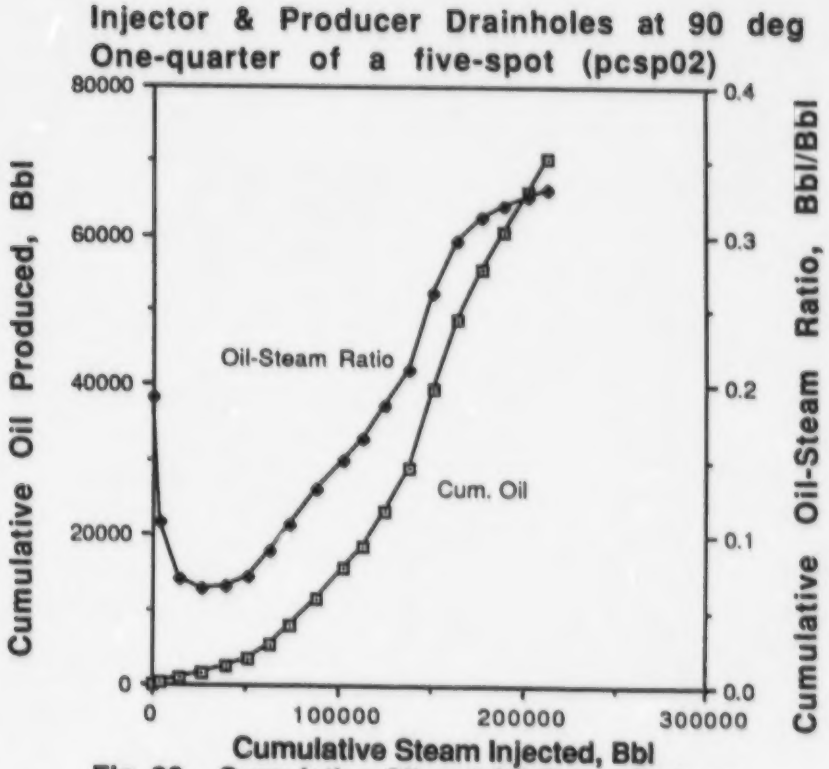


Fig. 38 - Cumulative Oil and Oil-Steam Ratio vs. Cumulative Steam Injected for Injector and Producer Drainholes.

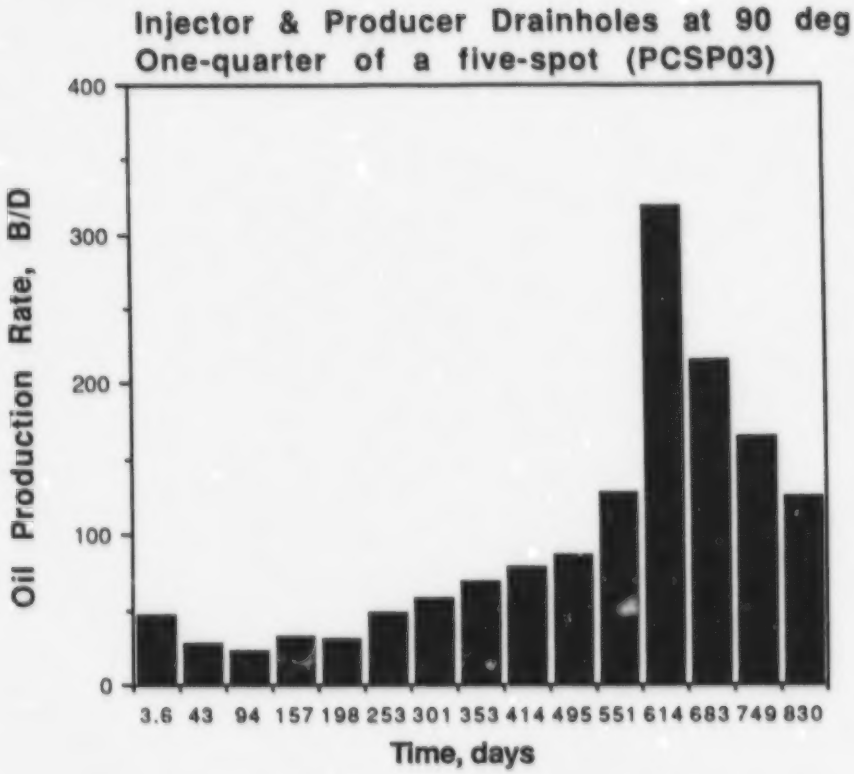


Fig. 39 - Oil Production Rate vs. Time for Injector and Producer Drainholes.

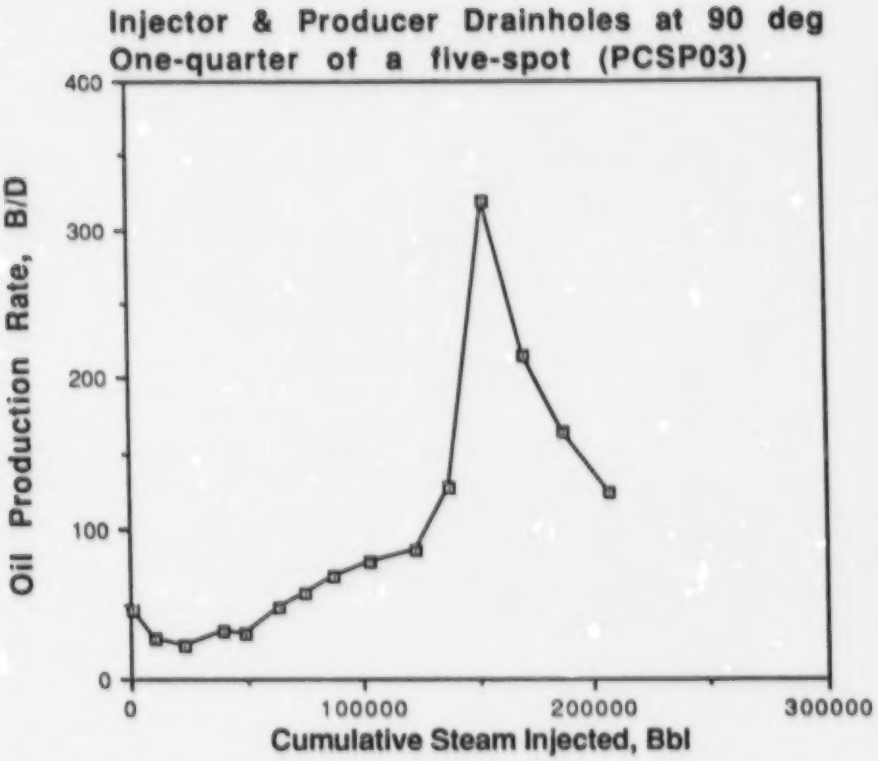


Fig. 40 - Oil Production Rate vs. Cumulative Steam Injected for Injector and Producer Drainholes.

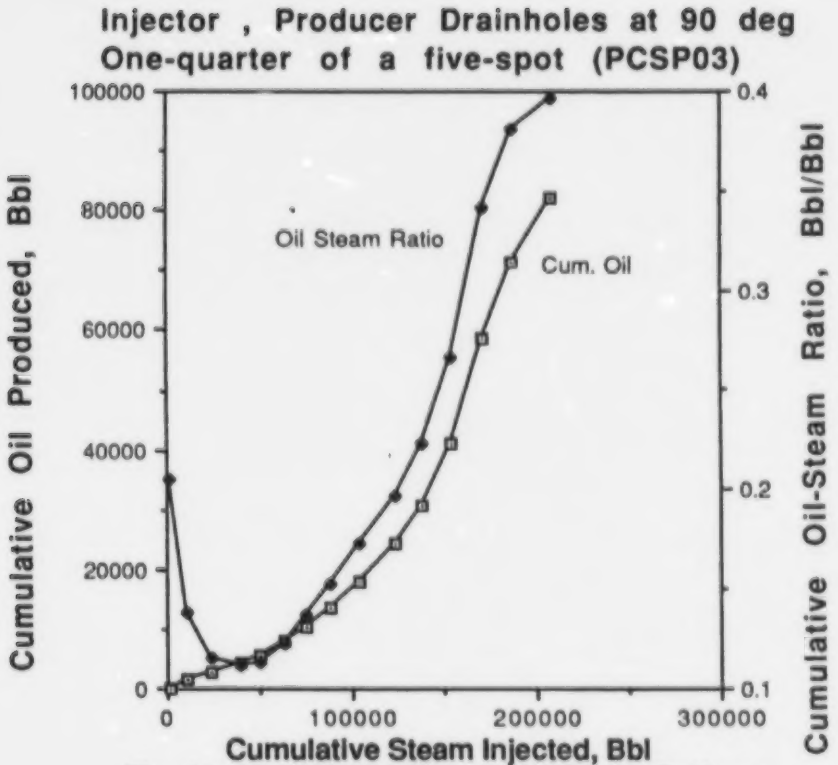


Fig. 41 - Cumulative Oil and Oil-Steam Ratio vs. Cumulative Steam Injected for Injector and Producer Drainholes.

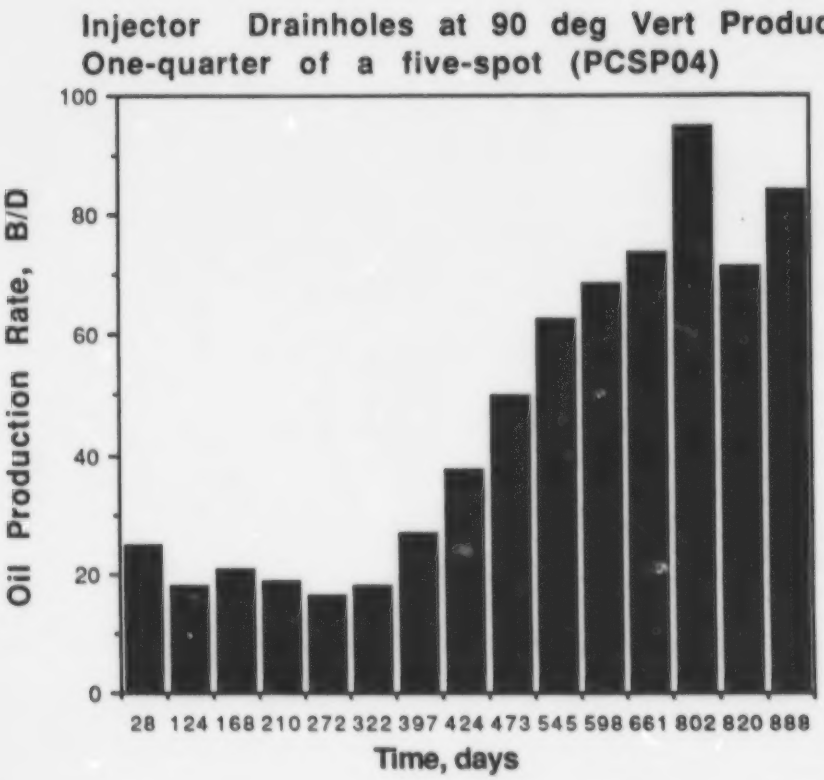


Fig. 42 - Oil Production Rate vs. Time for Injector Drainholes and Vertical Producer.

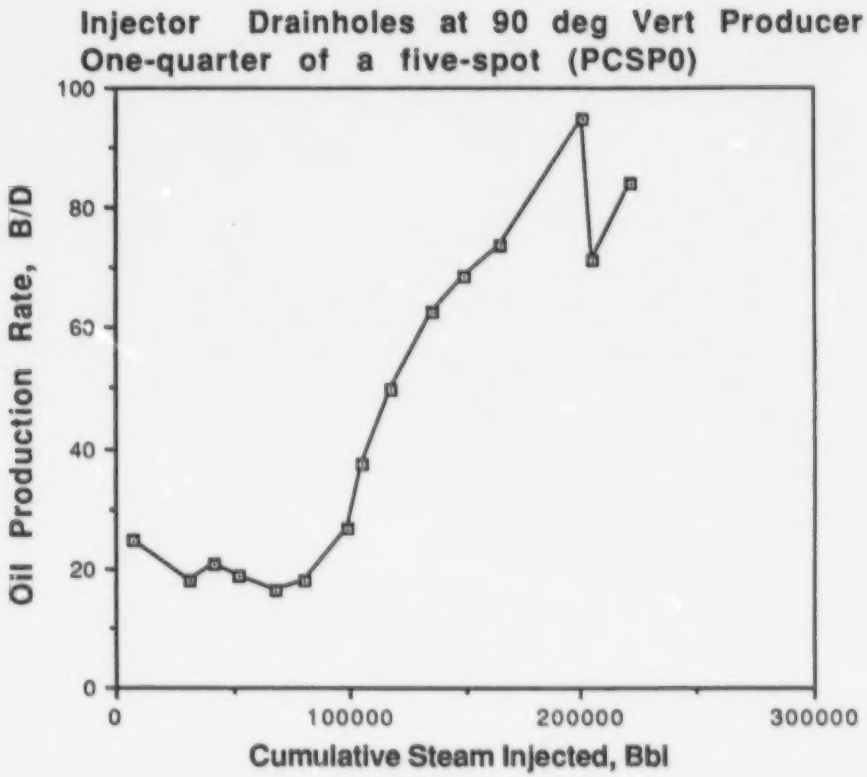


Fig. 43 - Oil Production Rate vs. Cumulative Steam Injected for Injector Drainholes and a Vertical Producer.

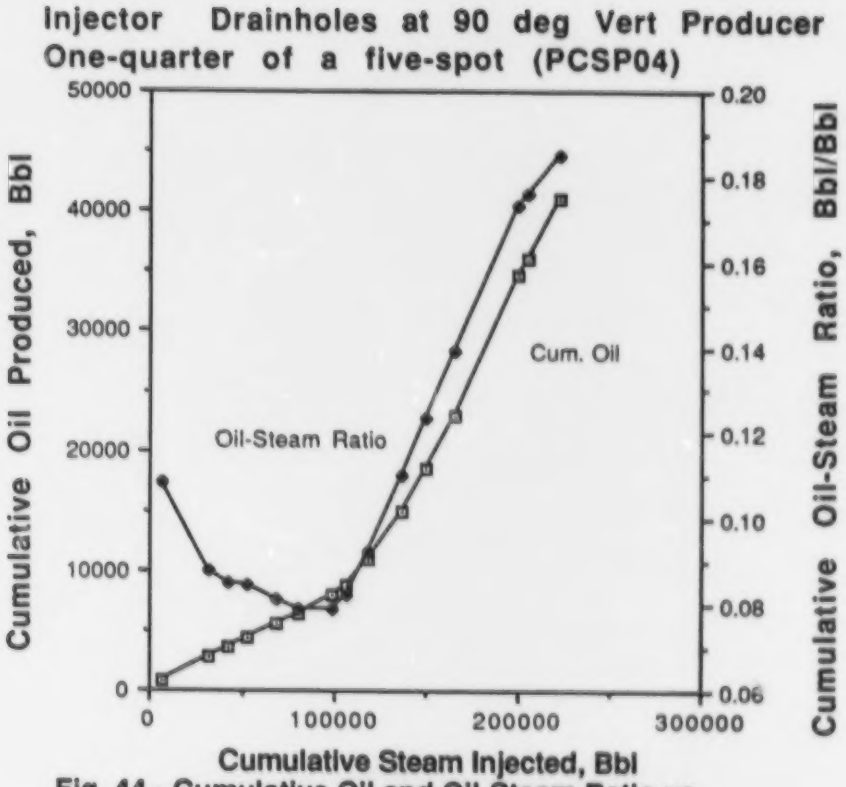


Fig. 44 - Cumulative Oil and Oil-Steam Ratio vs. Cumulative Steam Injected for Injector Drainholes and a Vertical Producer.

completed in the lower layer only. The performance curves for this case are shown in Figs. 42-44. The total oil recovery in this run was approximately one-half of that in the other runs.

Two runs, PCSP01A and HIHP03A were conducted to observe the effect of initial temperature on the steamfloods PCSP01 and HIHP03, discussed previously. Figure 45 compares selected run indices for the two sets of runs. It is seen that the oil recovery was much lower when steam injection is carried out at the original formation temperature. More important, the injection pressures are far too high to be practical. Alternatively, if a maximum pressure limit was employed, the steam injection rate dropped to unacceptably low values.

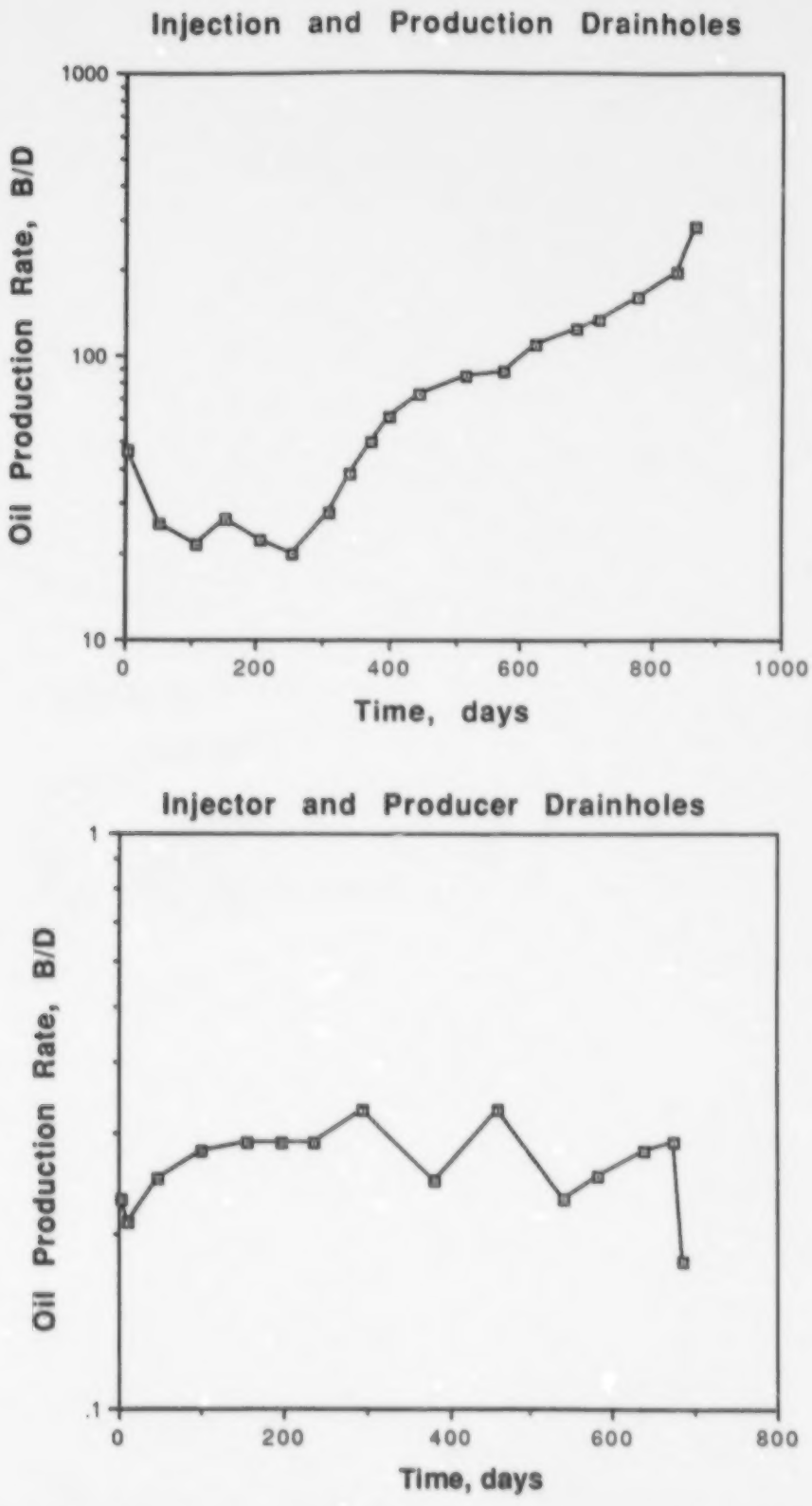


Fig. 45 - Comparison of the Oil Production Behaviour at 100 C (upper graph) and 15 C (lower graph) Initial Temperature.

CONCLUSIONS

The principal objective of this research was to incorporate the previously developed injection and production well models into a numerical simulator of steam injection processes, and then use the composite simulator to carry out simulations of steamfloods in the McMurray formation, using horizontal-vertical well combinations. The following conclusions are reached based upon the results of this study:

1. Simulation of wellbore hydraulics in a typical steamflood simulation is important, especially in the case of an injection well. The variation of steam pressure and quality with depth, and to a lesser extent, with time, has a considerable influence on performance prediction. In the case of a producer, on the other hand, wellbore hydraulics may not make a significant difference in predictions.

2. Steamflooding in the McMurray formation would be practical only if the formation is preheated by a suitable process. Steam injection at the original formation temperature led to high injection pressures, well above the fracture pressure.

3. Considerable variations in steamflood performance were observed depending on the horizontal-vertical well combination employed. The oil-steam ratios varied from less than 0.1 to almost 0.5, for the same steam injection rate and pattern size, which underscores the need for simulations to screen many different cases for field design.

4. Based upon the special well runs, the well combinations involving short horizontal wells and drainholes appear to be the most effective. For example, the case in which both the injector and producer consist of two horizontal wells at right angles, extending over a distance of 60% of the side of the 5-acre pattern, oil recovery was 40%, with a cumulative oil-steam ratio of 0.48 bbl/bbl.

RECOMMENDATIONS

Based upon the experience gained in this study, several recommendations are offered for further work, as well as for possible field applications.

•The simulation results show the strong dependence of the steamflood performance on the injection-production scheme employed. Many schemes beyond those discussed here can be devised, and tested in a semi-quantitative manner. In particular, a proper representation of the injection well is very important.

•Additional combination cyclic steam stimulation and steamflooding runs should also be conducted. This would put formation preheating on a more practical level. Similarly, pre-heating using fractures should also be studied.

•Use of horizontal wells in "top water" (and bottom water) situations should be studied. This by itself is a very extensive area, and merits further work.

•The results show that horizontal steam injectors may be more effective than vertical injectors. Limited field tests should be carried out to determine the injectivities in the Athabasca oil sands.

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APPENDIX A
Statement of Work

APPENDIX "A"

STATEMENT OF WORK

TITLE: APPLICATION OF HORIZONTAL WELLS IN COMBINATION WITH VERTICAL WELLS FOR ATHABASCA OIL SAND DEPOSITS [Part of Energy, Mines & Resources Cost-Shared Energy Conversion Program and Part of the Program of the Federal Panel on Energy R&D (PERD)]

The proposed research will address two problems, which are briefly as follows:

1. For a given set of conditions, what is the optimal combination of vertical and horizontal wells? The variables include: oil viscosity, number of layers, horizontal well length, well placement, areally and vertically, bottom or top water and steam injection constraints. Specific attention will be given to the Bechtel type short radials in this work.

2. What is the effect on predicted oil recovery and steam-oil ratio if the horizontal well model developed previously by Petro-Canada is employed in lieu of the current approach of modelling well with a string of relatively small blocks in a conventional simulator? The main task is to compare the conventional well simulation model results to the results from the modified simulator.

The first objective would assist in assessing the potential of horizontal wells and provide fresh insights into the field studies, which do not have the flexibility of a simulator. The second objective would be useful for validating simulation results, our own as well as those reported by others. The various tasks of the work program are listed below:

TASK 1: Review the Recent Models

The objective is to carry out a careful survey of the three horizontal well models under development by research institutions and oil companies; Mobil Oil, Mr. S.D. Joshi, and ARC. These have not been published in most instances. An effort will be made to determine how they compare with the present work. This will be primarily accomplished by personal contact. Any published material will also be utilized. This is not an exhaustive review of literature, since this has already been done. Rather, it is an effort to keep abreast of the most recent developments.

TASK 2: Choose the Simulator

The horizontal injector and producer models already developed by Petro-Canada are to be incorporated into an existing simulator. The objective is to determine which of the existing simulators is best suited for this purpose. Several commercially available simulators such as CMG, SSI and Mr. Kaz Winsome's model will be considered, although preference will be given to SSI's Therm model which is currently used by PCEJ staff.

TASK 3: Incorporate Well Model

This is a major task in this study. The purpose is to incorporate the horizontal injector and producer models already developed by Petro-Canada into the Simulator chosen under Task 2. The Simulator will be modified in such a way that the new well models are incorporated with the least increase in the required CPU time. For this purpose the simulator equations will be altered and an effort will be made to include the well models in an implicit manner. Most of the work under this task will be carried out in consultation with the vendor of the chosen commercial simulator.

TASK 4: Test the Model

Once the horizontal injector/producer models are incorporated into the chosen simulator, the modified simulator will be tested for overall performance. It is expected that 3 or 4 short computer runs will be needed for this purpose. As a result of successful completion of this task, it is expected that the steam injection simulator will be fully operational for subsequent studies.

TASK 5: Set up Variables

This task is concerned with determining the type of runs to carry out, and the variables to consider. It is intended to carry out 5-6 steamflood studies, varying steam injection rate, pattern spacing, formation thickness, and bottom (or top) water thickness. Other variables such as vertical permeability distribution or relative permeability hysteris may be selected/substituted depending on the results.

TASK 6: Combination Runs

The purpose of these runs is to determine which horizontal/vertical well combinations are most promising from the standpoint of steamflooding. It is expected that approximately 8 runs will be conducted to isolate the more important variables from those considered under Task 5. In these runs, vertical injectors will be combined with horizontal producers.

TASK 7: Conventional Model vs New Model

The conventional approach used in horizontal well simulation is to allocate the injection or production rates to a horizontal suite of blocks, using the productivity indices of vertical wells. Under this task, the purpose is to compare this approach with that using the modified simulator, which will have a much more realistic representation of horizontal injectors and producers. It is expected that three to five simulation runs would suffice for this purpose. An effort will be made to choose data from the previous horizontal well studies carried out by Petro-Canada, using the conventional approach.

TASK 8: Horizontal/Vertical Runs

Under this task, the final runs will be carried out. It is expected that 10 runs will suffice. The purpose of these runs is to test a number of horizontal-vertical well combinations for steamflooding in the PCEJ leases. Depending on the results, such as Oil Steam Ratio (OSR) less than 0.1., cyclic steam simulations may also be considered. Basically, it is intended to determine what is the "best" combination of vertical injectors and horizontal producers, for a given spacing, using as few wells as possible. In a few runs, horizontal injectors will also be considered. It is expected that five runs will be conducted under this task. The run set-up will be determined in consultation with the PCEJ Technical Sub-committee in order to employ as close to the field data as possible.

TASK 9: Final Report

T..e aforementioned work will be discussed in detail in the final report, to be prepared under this task.

APPENDIX B
Rock and Fluid Data

Table B.1

PCEJ AREA 1 LEASE 70 RESERVOIR DESCRIPTION
WELL 13-27-84-11 W4M

Res. Press. = 2500 kPa
Res. Temp. = 15°C
Viscosity Data = centrifuge 13-17

K.B. = 563.2 m
Relative Perm Data #

DEPTH mKB	LAYER #	THICKNESS m	Sw	So	Sg	Kh md	K v md	ϕ	REMARKS
268.0									
	1	3.8	0.18	0.82	0.00	900	360	0.27	
271.8									.3m shale streak between layers 1 and 2
	2	3.2	0.19	0.81	0.00	900	360	0.26	
275.0									
	3	1.7	0.21	0.79	0.00	1000	400	0.30	
276.7									
	4	9.0	0.19	0.81	0.00	1300	520	0.32	
285.7									.6m shale streak between layers 4 and 5
	5	2.9	0.25	0.75	0.00	1000	400	0.28	
288.6									
	6	1.0	0.99	0.01	0.00	0.5	0.2	0.16	Shale streak
289.6									
	7	2.5	0.09	0.91	0.00	1400	560	0.31	
292.1									.2m shale streak between layers 7 and 8
	8	2.9	0.11	0.89	0.00	1600	640	0.33	
295.0									
	9	6.0	0.15	0.85	0.00	1600	640	0.33	
301.0									
	10	3.0	0.13	0.87	0.00	1600	640	0.33	
304.0									
	11	4.0	0.15	0.85	0.00	1600	640	0.35	
308.0									
	12	4.2	0.22	0.78	0.00	1600	640	0.36	
312.0									
	TOTAL	43.2	0.17	0.83	0.00	1350	550	0.32	

PERFORATION = 302 - 310 mKB

Table B.2

PCEJ 13-27-84-11 W4M

VISCOSITY DATA

TEMPERATURE, °C	OIL VISCOSITY, mPa.s
15.0	783 000
37.4	37 500
59.9	4 100
82.3	790
104.8	226
127.2	85.9
149.7	40.0
172.1	21.6
194.6	13.0
217.0	8.52
239.5	5.94
261.9	4.34
284.4	3.30
306.8	2.58
329.3	2.07
351.7	1.70
374.1	1.41
396.6	1.19
419.0	1.02
459.4	.758

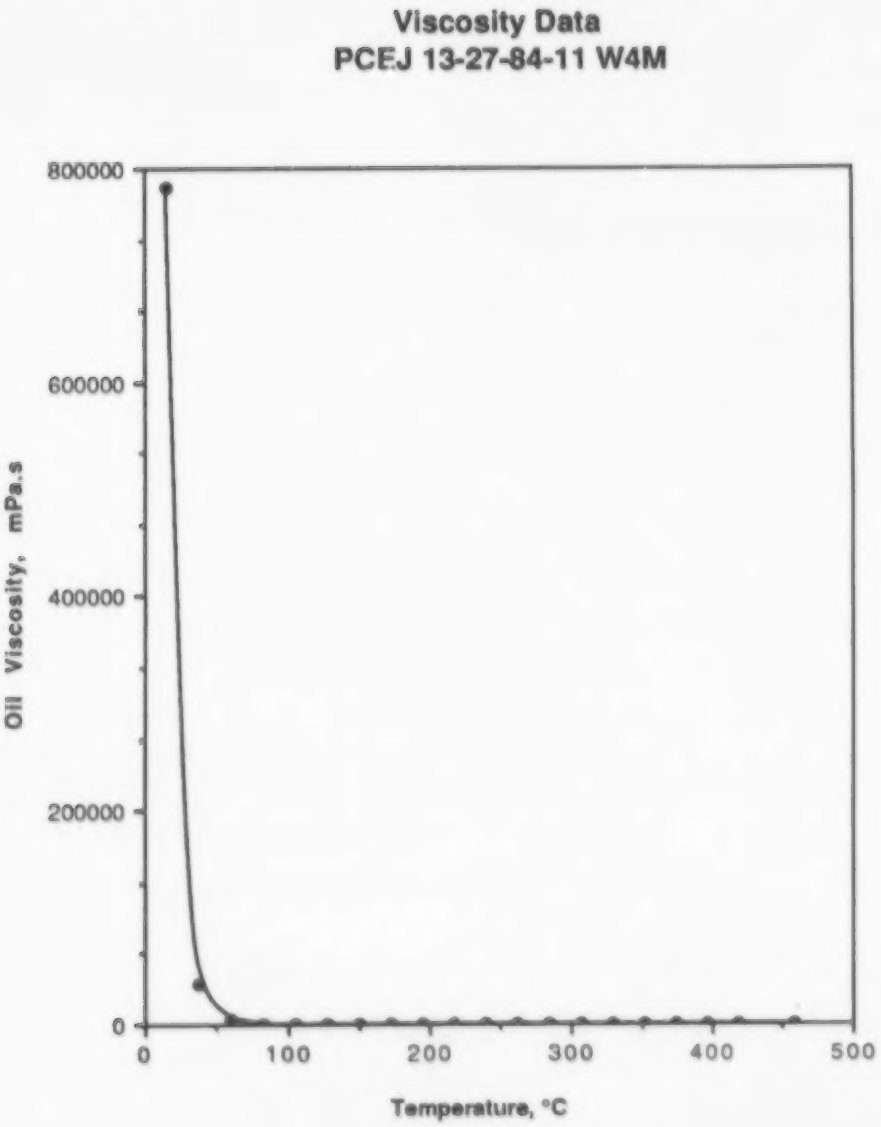

Fig. B.1 - McMurray Bitumen Viscosity as a Function of Temperature.

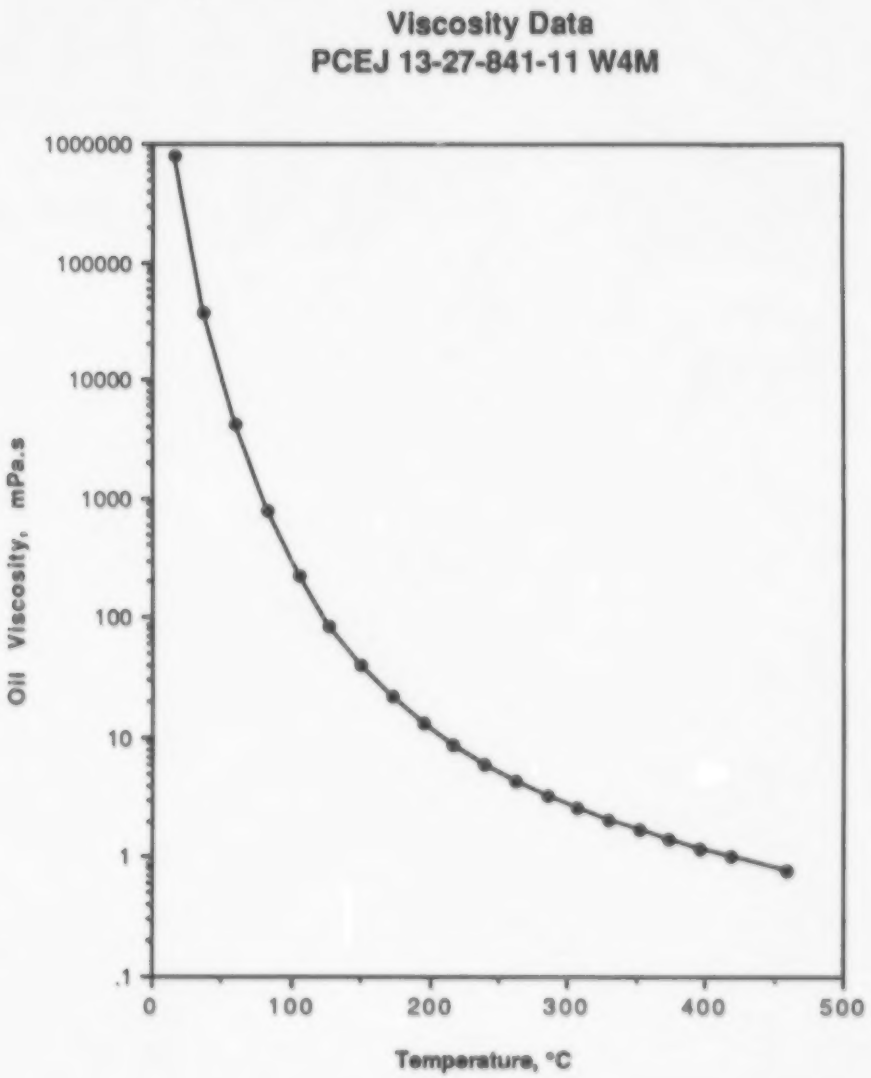

Fig. B.2 - McMurray Bitumen Viscosity as a Function of Temperature on Semi-log Coordinates.

Table B.2

PCEJ 13-27-84-11 W4M

WATER-OIL RELATIVE PERMEABILITY DATA

S_w	K_{rw}		K_{row}	
	R. Type 1 (injection)	R. Type 2 (production)	R. Type 1 (injection)	R. Type 2 (production)
.120	0.0000	0.0000	1.0000	1.00
.200	.0035	.0011	.690	0.950
.300	.0120	.0070	.300	.833
.400	.024	.0168	.184	.667
.450	.034	.0238	.146	.583
.500	.046	.0322	.115	.500
.550	.058	.0399	.088	.417
.600	.076	.0532	.066	.338
.650	.098	.0672	.046	.250
.700	.128	.0896	.029	.167
.740	.155	.1085	.015	.100
.800	.190	.1500	.000	.000
1.0000	1.0000	1.0000	0.0000	.000

Table B.3

PCEJ 13-27-84-11 W4M

GAS-OIL RELATIVE PERMEABILITY DATA

S_{liq}	K_{rog}	K_{rg}
.340	0.0000	1.000
.380	.0036	.904
.420	.0070	.808
.460	.0120	.712
.500	.0250	.616
.540	.0440	.520
.600	.080	.376
.640	.115	.278
.680	.160	.198
.720	.204	.135
.760	.257	.090
.800	.325	.056
.840	.425	.032
.880	.540	.013
.920	.700	.003
.964	.892	.000
1.000	1.000	.000

Table B.4

PCEJ 13-27-84-11 W4M

ROCK PROPERTIES

Rock Compressibility	1.42×10^{-2}/MPa
Reservoir Rock Heat Capacity	2350.0 KJ/m^3 °C
Reservoir Thermal Conductivity	150.0 KJ/m day °C
Overburden Heat Capacity	2702.76 KJ/m^3 °C
Overburden Thermal Conductivity	150.0 KJ/m day °C
Overburden Heat Capacity	2655.81 KJ/m^3 °C
Underburden Thermal Conductivity	150.0 KJ/m day °C
Initial Reservoir Temperature	15°C
Initial Reservoir Pressure	2500 kPa

FRACTURE PROPERTIES

PFRAC[1]	4700 kPa
CRFRAC[2]	0.040/MPa
DKDP[3]	200
SWTCON[4]	10

1. Fracture opening and closing pressure
2. Modified rock compressibility in fractured grid block
3. Fractional increase in permeability with respect to pressure 1/100 kPa
4. Super upstream weighting factor for the convective heat flow term (Y. Ito, SPE 11193, 1982 SPE Fall Meeting, New Orleans)

Table B.5

PCEJ 13-27-84-11 W4M

RESERVOIR FLUID PVT PROPERTIES

QUANTITY	UNITS	DEAD OIL	LIGHT ENDS
Component Number in Model	-	i = 2	i = 3
Master Phase Number in Model	-	Oil (j_i = 2)	Gas (j_i = 3)
Molecular Weight	Kg/Kg mole	560	21
Specific Gravity in Master Phase	-	1.0086	0.7264 (air=1)
Stock Tank Density	Kg/m^3	1008.6	-
Critical Pressure	atm	-	46.9014
Critical Temperature	°k	-	221.1111
Initial Solubility in Oil Phase	Nm^3/m^3	-	5.78
Initial Mole Fraction in Oil Phase	-	0.9105	0.0895
KV1 in Oil Phase	-	1.0	1.9755×10^{-2}
KV2 in Oil Phase	atm	0.0	-9.4549×10^{-2}
KV3 in Oil Phase	1/atm	0.0	2.2594×10^{-5}
KV4 in Oil Phase	°k	0.0	-57.8016
KV5 in Oil Phase	°k	0.0	173.1275
Partial Volume in Oil Phase	m^3/Kg	9.9147×10^{-4}	1.0352×10^{-3}
Compressibility in Oil Phase	1/atm	4.97×10^{-5}	4.97x10
Thermal Exp. Coef. in Oil Phase	1/°C	6.12×10^{-4}	6.12×10^{-4}
Specific Heat	KJ/Kg-°C	2.094	2.103
Minimum Viscosity in Oil Phase	cp	1.0×10^{-5}	1.0×10^{-5}
VISO in Oil Phase		0.282×10^{10}	1.0×1^{-30}
NVIS in Oil Phase		-3.3813	9.84
VISO in Gas Phase		-	4.977×10^{-6}
NVIS in Gas Phase		-	1.2166
Dead Oil Viscosity at (1 atm and 15°C)	cp	783,000	-
Mixture Viscosity at Reservoir Conditions (2500 kPa atm, 15.00°C)	cp	62,492	-